COMPARISON OF PHOTOVOLTAIC ENERGY SYSTEMS FOR THE SOLAR VILLAGE

by

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ABSTRACT

Three different solar photovoltaic (PV) energy systems are compared to determine if the electrical needs of a solar village could be supplied more economically by electricity generated by the sun than by existing utility companies. The solar village, a one square mile community of 900 homes and 50 businesses, would be located in a semi-remote area of the Arizona desert. A load survey is conducted and information on the solar PV industry is reviewed for equipment specifications, availability, and cost. Three specific PV designs, designated as Stand-Alone, Stand-Alone with Interconnection, and Central Solar Plant, were created and then economically compared through present worth analysis against utility supplied electrical costs. A variety of technical issues, such as array protection, system configuration and operation, and practicability, are discussed for each design. The present worth analysis conclusively shows none of the solar PV designs could supply electricity to the solar village for less cost than utility supplied electricity, all other factors being equal. No construction on a solar village should begin until the cost of solar generated electricity is more competitive with electricity generated by coal, oil, and nuclear energy. However, research on ways to reduce solar PV equipment costs and on ways to complement solar PV energy, such as the use of solar thermal ponds for heating and cooling, should continue.

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SECTION 1.0
INTRODUCTION

The purpose of this report is to compare three different solar photovoltaic (PV) energy systems to determine if the electrical needs of a solar village could be supplied more economically by electricity generated by the sun than by existing utility companies. The solar village is a one square mile community consisting of approximately 900 residential houses and 50 businesses of various sizes. The designs are based on the criteria of being located in the Phoenix, Arizona area and are generalized in such a way that the designs can be applicable for future villages located in different areas of the Southwest, if they are economically feasible. Thus, the flexibility of the project will enhance its usefulness for other solar village designers.

A thorough review of the literature applicable to the PV electrical energy generation for a solar village of this size was conducted to determine if any prior research had already been done. Based on the results of this search, this report is the first to be done concerning the economic feasibility of supplying solar generated electricity to meet the entire electrical needs of a solar village, through a variety of designs.

The designs, if feasible, will be suitable for immediate installation in a selected solar village. The system designs will utilize

commercially available, state-of-the-art PV components to assure that the developed systems can be installed today.

Because of the magnitude of a project this size, the designs of the village in this paper are based solely on the use of electricity generated by solar photovoltaic (PV) modules. The designs will not consider thermal cooling ponds, specially constructed houses, or other passive solar energy uses such as heating water. This report examines what is the best possible electrical design available now, keeping within reasonable economic constraints.

1.1 OBJECTIVES

The results will demonstrate the most efficient solar energy strategy for alternate, environmentally acceptable, energy supply of residential, business, and commercial customers. The work will be divided into the following major tasks:

Load Survey: The expected load and load gross for different (residential, commercial, business customers) will be studied.
The peak load, yearly and monthly energy need, and the expected average load will be determined.

Using this data, a load pattern will be established for the Phoenix solar village. The load gross in the next 10 year period will also be established.

<u>Selection of Alternative Designs</u> Several alternative PV energy generation systems are designed together with feeders and utility interfaces to meet the load requirements determined during the load survey. The alternative designs include the following:

- PV system on individual houses with and without energy storage,
  - With houses interconnected
  - With houses not interconnected
- Centralized energy system.

The designs will consider the effects of:

- The capacity of the supporting utility system,
- Different backup power sources,
- Different levels of insolation,
- Different array sizes.

SECTION 2.0
LOAD ANALYSES

Before any solar PV designs can be considered, a basic load survey of the energy needs for the solar village must be completed. Using information provided by the Arizona Public Service Company (APS) of Arizona, the load pattern for the Phoenix area solar village is established. This load survey includes the expected loads for residential and commercial/business customers only. The village is not intended for industrial customers because of their high energy consumption.

The average "connected load" for a residential house in the Phoenix area is roughly 12 kW according to officials at APS. The connected load is the kW sum of all of the electric loads in the house. A typical house or business, however, doesn't have all of its electrical loads on all at once. Thus, the demand will be somewhat smaller than 12 kW depending on the time of year.

The information supplied by APS is based on customer electricity use during four months of the year: January, April, August, and October. The survey conducted by APS includes the average hourly load demand and energy demand. The *load factor* is used to determine the maximum demand in kW/Day and is defined as follows:

$$\text{Load Factor} = \frac{\text{Average Load}}{\text{Peak Load}}$$

The annual load factor reported by APS is 24.3% for residential customers and 72% for commercial customers. The maximum demand is measured on a one hour interval.

2.1 RESIDENTIAL

The results for the residential customers are as listed in Table 2-1.

TABLE 2-1. RESIDENTIAL ENERGY USAGE

Month	Average KWH/Mo	Average KWH/Day	Max Demand KW/Day
January	1,639	52.3	6.81
April	1,546	51.5	5.07
August	2,535	81.8	10.8
October	1,760	56.8	5.29

The graphs shown below are the hourly KWH energy use curves for a typical house corresponding to the above four months of the year.

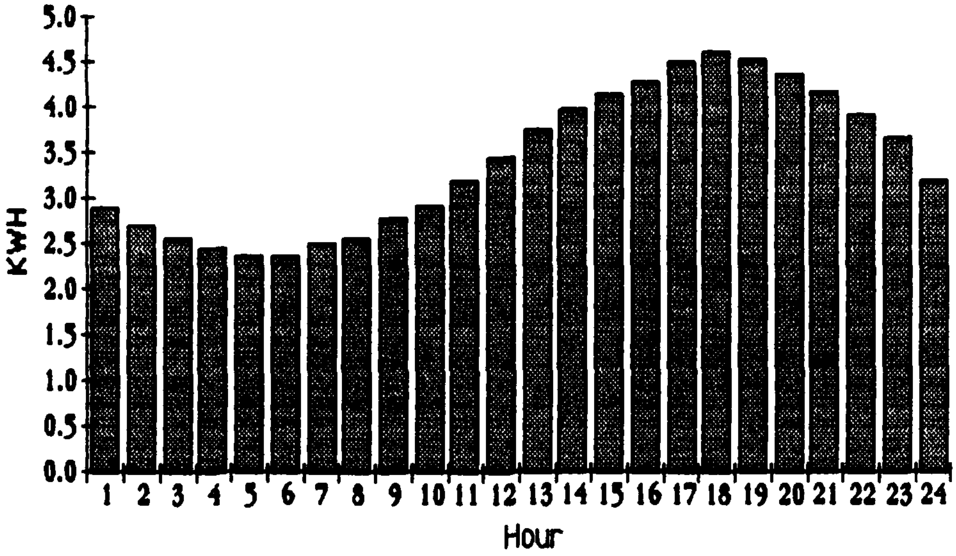


Figure 2-1. Average Daily Residential Energy Use Curves-August 1986

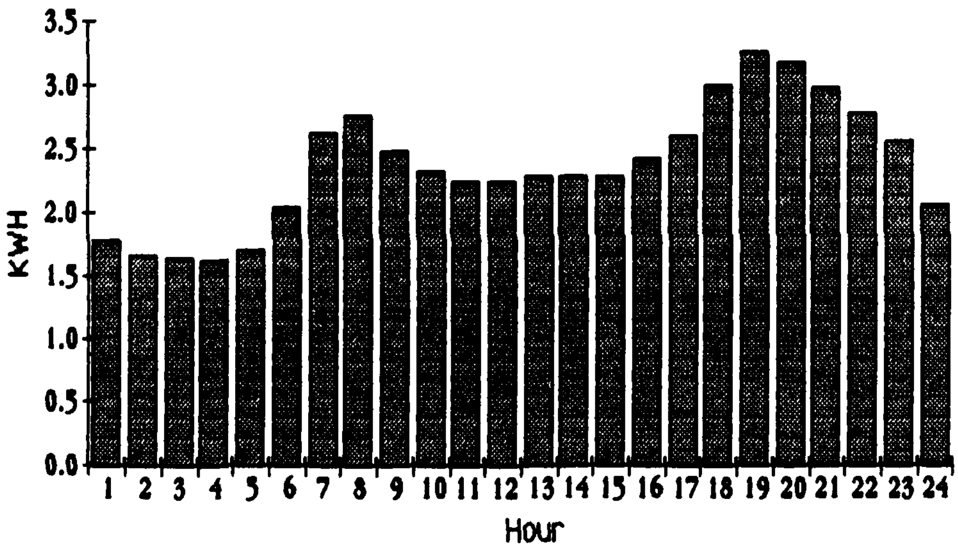


Figure 2-2. Average Daily Residential Energy Use Curves-October 1986.

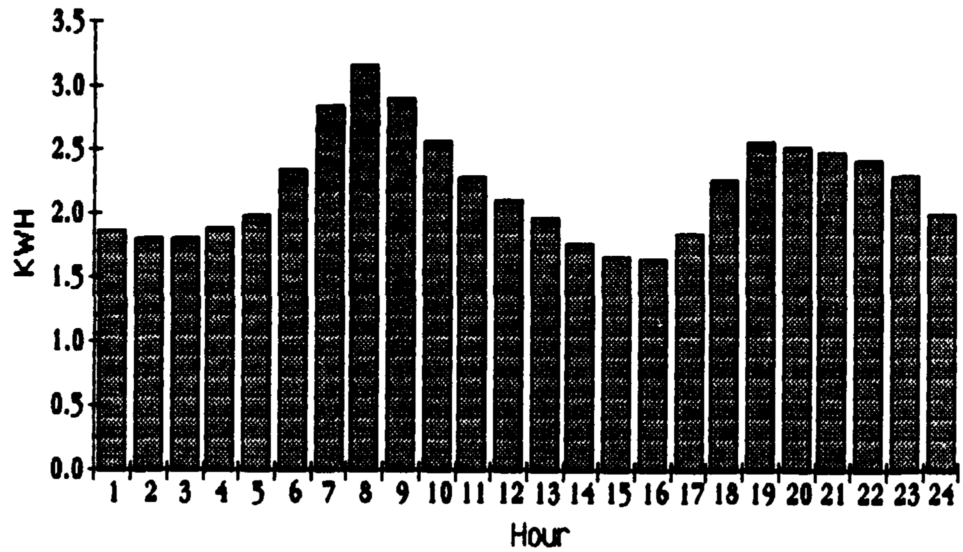


Figure 2-3. Average Daily Residential Energy Use Curves-January 1987.

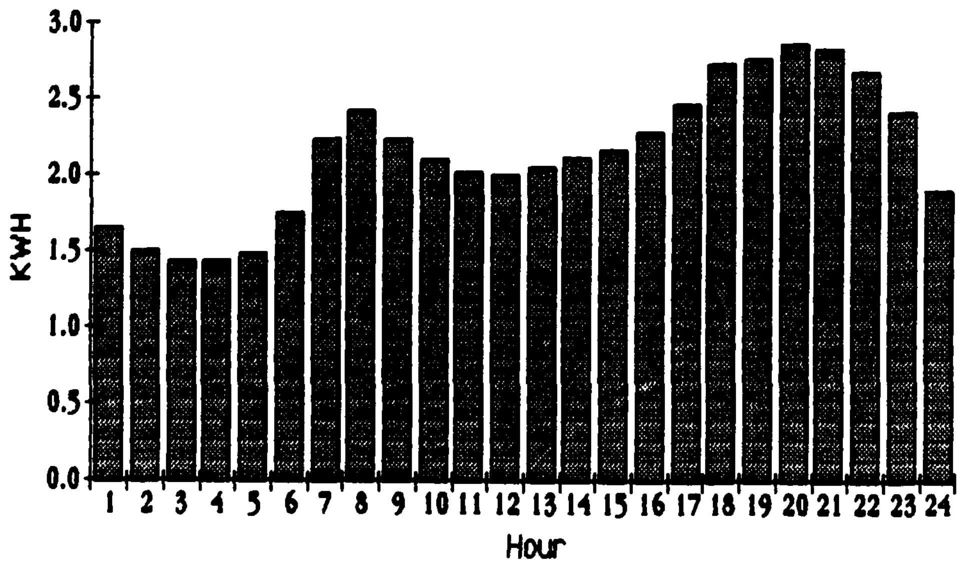


Figure 2-4. Average Daily Residential Energy Use Curves-April 1987.

3.2 COMMERCIAL/BUSINESS

The results for commercial and business customers are as listed in Table 2-2.

TABLE 2-2. COMMERCIAL/BUSINESS ENERGY USAGE

Month	Average KWH/Mo	Average KWH/Day	Max Demand KW/Day
January	6052.94	195.25	16.90
April	6495.53	216.00	19.28
August	9014.79	290.80	23.47
October	7362.96	237.52	21.68

Commercial customers have a wide variety of energy needs depending on their size and function. The solar village will only have medium and light commercial customers. A grocery store such as Safeway or Bashas is considered to be a medium commercial customer with a demand of approximately 219 kW. A light commercial customer might be a Circle K with a demand of approximately 29.1 kW. A very light commercial customer may be a small store with a demand of around 5 kW. The majority of the commercial customers in the solar village will be on the light to very light side. This is why the maximum demand for the month of August is around 23.47 kW.

The average daily energy use curves for a typical commercial customer for four months out of the year follow.

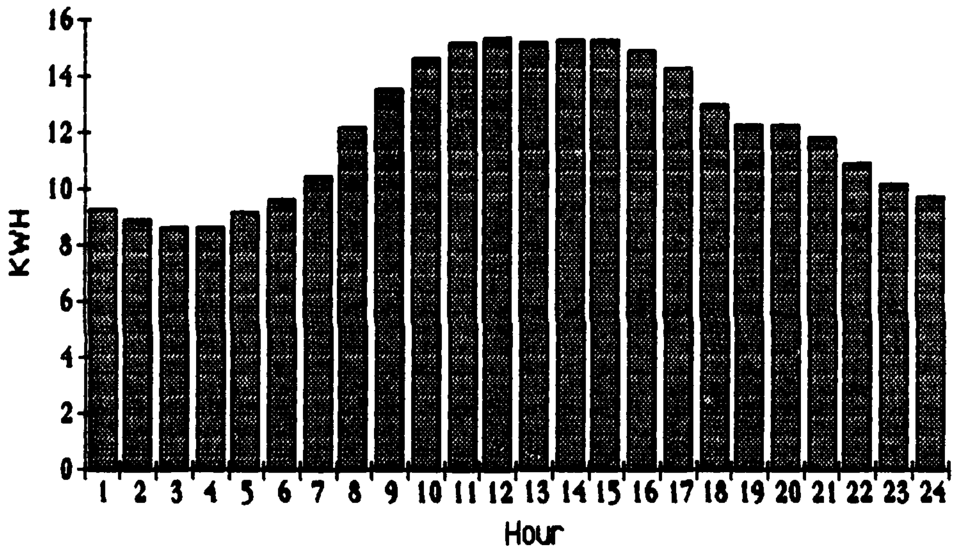


Figure 2-5. Average Daily Commercial Energy Use Curves-August 1986.

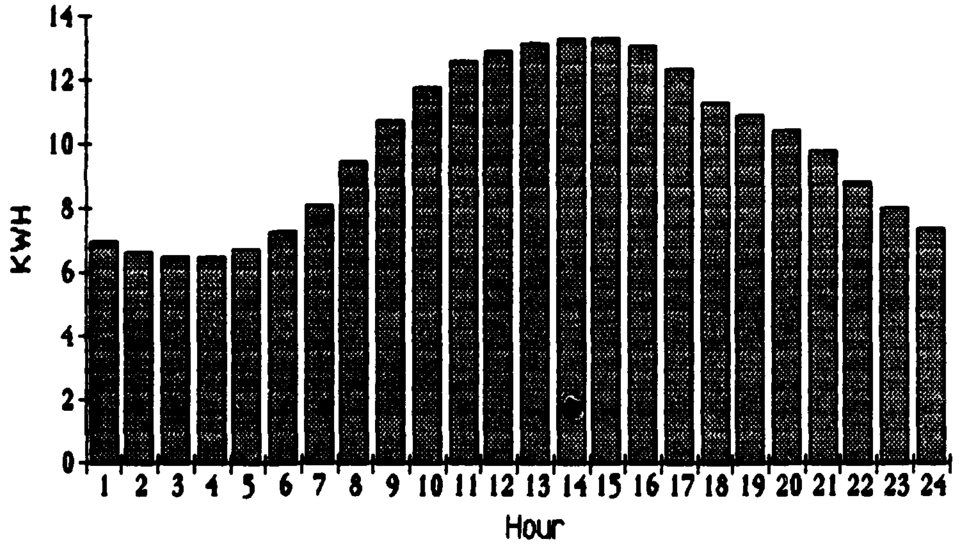


Figure 2-6. Average Daily Commercial Energy Use Curves-October 1986.

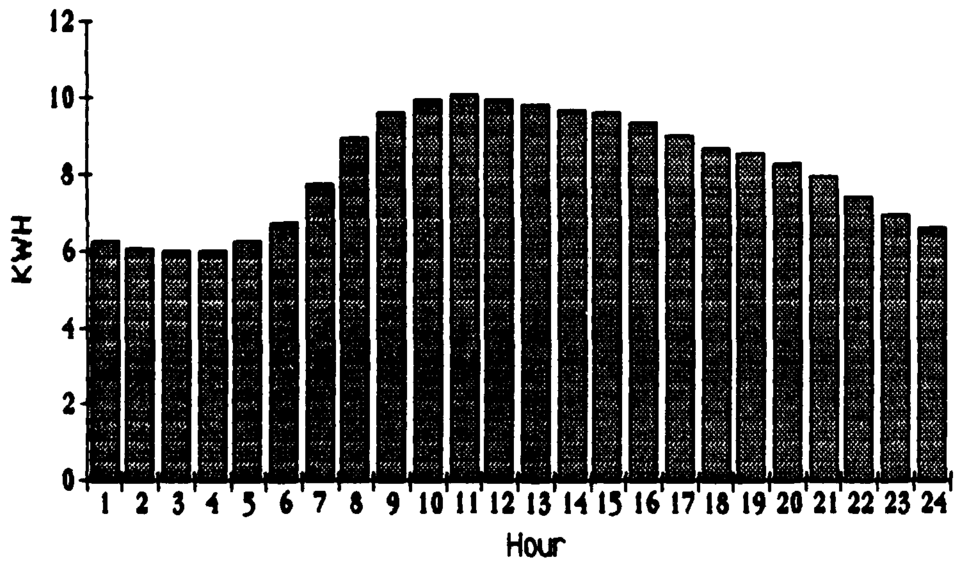


Figure 2-7. Average Daily Commercial Energy Use Curves-January 1987.

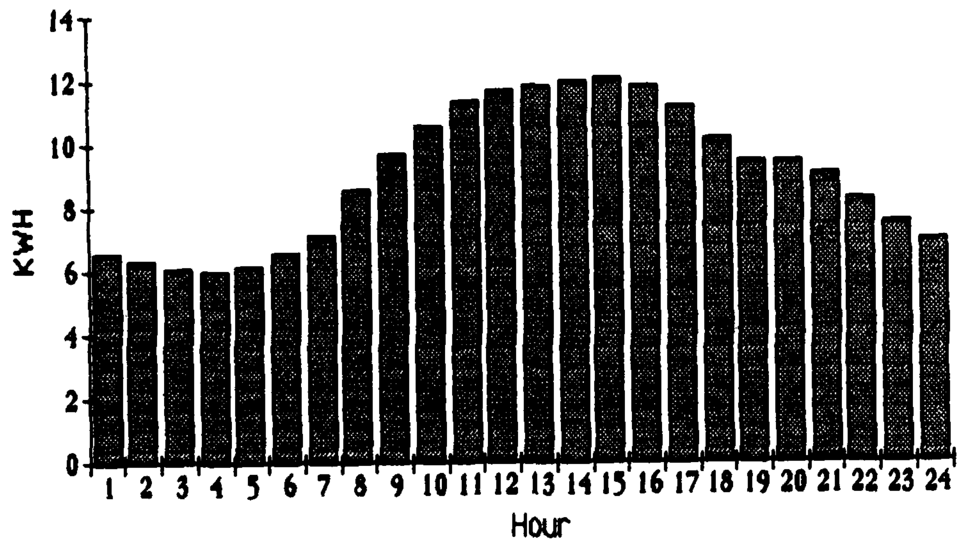


Figure 2-8. Average Daily Commercial Energy Use Curves-April 1987.

2.3 GROSS LOAD CALCULATIONS

According to electrical engineers at Salt River Project (SRP), also located in Phoenix, Arizona, a new residential area of one square mile consists of approximately 900 homes with some small shops and businesses such as convenience stores and gas stations, etc. Realizing the solar village will be isolated from towns and cities, it's logical to assume more businesses are needed to support the residents of the village. Thus, for purposes of analysis, there will be 50 commercial and business customers in the village.

Now, the approximate gross loads for residential and commercial/business customers, and the two combined, can be found.

2.3.1 Residential

The results for the 900 residential customers are listed in Table 2-3.

TABLE 2-3. TOTAL RESIDENTIAL ENERGY USAGE

Month	Average MWH/Mo	Average MWH/Day	Max Demand MW/Day
January	1.475E3	47.10	6.129
April	1.391E3	46.35	4.563
August	2.282E3	73.62	9.720
October	1.584E3	51.12	4.760

2.3.2 Commercial/Business

The results for the 50 commercial and business customers are listed in Table 2-4.

TABLE 2-4. TOTAL COMMERCIAL/BUSINESS ENERGY USAGE

Month	Average MWH/Mo	Average MWH/Day	Max Demand KW/Day
January	302.65	9.76	845
April	324.78	10.80	964
August	450.74	14.54	1173
October	368.15	11.88	1084

2.3.3 Total Gross Load for the Village

The following values in Table 2-5 are the total combined loads for the residential and commercial customers.

TABLE 2-5. TOTAL GROSS LOAD

Month	Average MWH/Mo	Average MWH/Day	Max Demand MW/Day
January	1.777E3	56.86	6.97
April	1.715E3	57.15	5.53
August	2.732E3	88.16	10.89
October	1.952E3	63.00	5.84

From the previous table it would seem the maximum peak demand for the entire village for the month of August is 10.89 MW. APS officials in the Distribution Section say the village would probably pull a yearly peak value of somewhere around 8 MW. This value is based on studies APS engineers have conducted in the past for an area approximately the size of the village located in a desert environment. If the village were to be in the mountains at a higher elevation, the peak demand would be around 3 to 4 MW.

2.3.4. Total Gross Loads after 10 years (assuming 3% Growth/year)

It's reasonable to expect some growth of the village over a period of 10 years in spite of its isolated location. Engineers in the Load Forecasting section at APS estimate growth in the Phoenix metropolitan area to be approximately 3 to 5% a year. Based on this estimate, Table 2-6 shown below gives the total gross loads of the village after 10 years of growth at 3% per year.

TABLE 2-6. TOTAL GROSS ENERGY USAGE AFTER 10 YEARS - 3% GROWTH

Month	Average MWH/Mo	Average MWH/Day	Max Demand MW/Day
January	2388.19	76.42	9.37
April	2304.81	76.80	7.43
August	3671.58	118.48	14.64
October	2623.32	84.67	7.85

A breakdown of the growth for each year is given in Table A.1 in Appendix A. It should be noted again that these figures are approximate and are based on values supplied by the Arizona Public Service Company and the Salt River Project on studies they have conducted on actual power and energy usage in the Phoenix metropolitan area. The load growth will occur due to more solar houses being built rather than increasing the size of the existing solar arrays. The load density will increase. Although some error is to be expected, the load estimates derived here are sufficiently accurate to allow a determination of which solar PV design is the most energy and economically efficient.

Once the load survey is completed, the next step is to design in detail a solar PV energy system for a residential house which can be used in the solar village. Two designs will be described: one with battery storage capability and the other with a utility inter-tie. A third design involving a central PV plant will also be briefly analyzed. Major factors such as cost, practibility, operation, maintenance, and safety will be discussed. All of the components described herein are on the market and are available for purchase today.

SECTION 3

TECHNICAL DESCRIPTION OF RESIDENTIAL DESIGN

3.1 GENERAL DESCRIPTION

Figure 3-1 shows a simplified diagram of a house with a solar PV system installed. The solar array is connected to the south facing side of the roof at an angle of approximately 20°. An equipment shack adjacent to the house contains the electrical equipment associated with the array. A vented battery storage area is shown below ground level outside and away from the house.

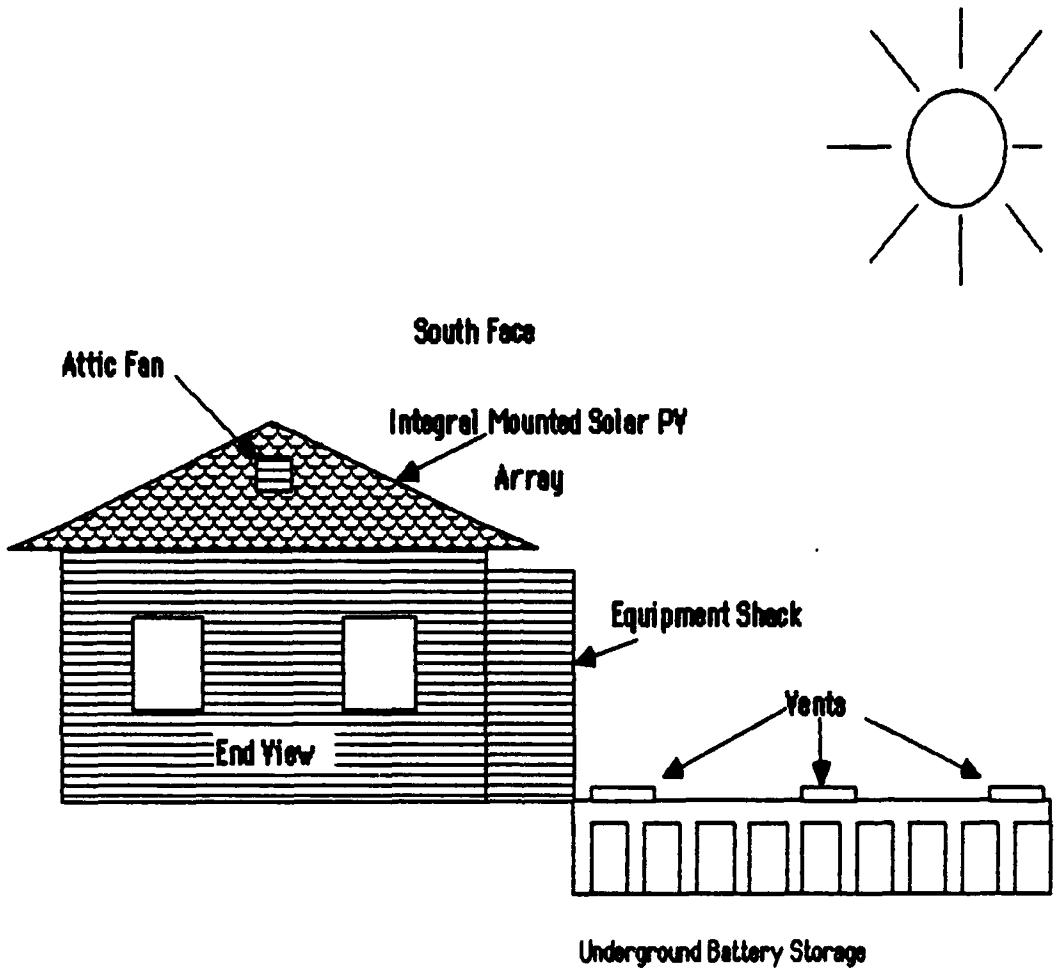


Figure 3-1. Block diagram of the PV system.

The PV array consists of 72 modules configured as 24 parallel strings of 3 modules apiece. The modules are ARCO Solar Model M-55 modules featuring single crystal cell technology.

The array converts solar insolation into DC electricity which is then sent to the power conditioning unit (PCU) for the utility-interactive design or to the power inverter for the stand-alone design.

In the utility-interactive design, the PCU is a self-commutated, current-sourced, DC-to-AC power converter incorporating maximum-power-point-tracking (MPPT) for the array. It also includes AC and DC contactors, an isolation transformer, and a control system that fully automates the operation of the PV system. The PCU converts the DC electricity into utility-compatible AC electricity. The AC output of the PCU is connected in parallel to the utility supply at the house's circuit breaker panelboard.

The PCU loads the PV array such that the array operates at its maximum power point and the converted array output (i.e., the AC output of the PCU) supplies the the residential (or onsite) loads. Surplus power available from the PCU is supplied to the utility system, when applicable, and residential load demand in excess of power available from the PCU is supplied by the utility.

For the stand-alone design, the array DC power is first fed into a battery controller and then into the power inverter. When the batteries are fully charged, the battery controller sends all of the available array power directly to the power inverter where it is converted to AC power. At night when the array is producing no power, the household loads are supplied by the batteries through the battery controller and the inverter.

During the day when the array is producing power, the battery controller uses excess array power, not needed for household use, to recharge the batteries. As will be shown later, a rather large array is needed to meet the electrical demands of the house and charge the batteries at the same time.

3.2 DESIGN ISSUES

This section presents a technical description of the components of the PV system, including some basic background information designed to help the reader.

A 3 kW (AC) PV system was selected for the design because it's typical of most utility-interactive residential systems and compatible with the available PCUs currently on the market. Almost all of the PCUs available today range from 1 to 3 kW. Some of these PCUs can be "stacked",i.e. connected together in parallel, to increase the power output of the solar PV array if more solar modules are added on. Of course, this adds significantly to the cost and complexity of the system with only one PCU.

From the load analysis for residential loads, the maximum demand was found to be 10.8 kW. This peak can occur for a particular house if, for example, the washing machine, dryer, oven, and air conditioner are running all at the same time. This maximum demand is rather large compared to the power output of the PV array.

Some type of load control system could be installed to prevent the total load demand from exceeding some predetermined value such as the maximum output of the solar PV array. Again, such a controller would be expensive and difficult to install. Thus, the basic residential design presented here will not consider the addition of such a controller. Of course, this decision almost necessitates the requirement for utility backup power as will be shown in a later section.

After specifying a nominal capacity, the design issues are:

- Selection of a solar PV module to be used in the array,
- Selection of a utility compatible PCU which defines the acceptable array input voltage range,
- Specifications of the array configuration which is the series-parallel arrangement of the modules.

The configuration must match the PCU input requirements which vary with the temperature extremes typical of the site. These are the issues which are critical to the design. Other issues are a matter of following good engineering practices.

3.3 COMPONENTS

3.3.1 Modules

ARCO Solar's Model M55 was chosen because it represents the state-of-the-art in solar module technology. The module was also selected on the basis of suitability, reliability, and cost. ARCO Solar is the world's leading manufacturer of solar modules and is not likely to go out of business as many smaller firms have done recently. Thus, replacement parts and service, if needed, should be available for years to come.

The M55 is ARCO Solar's most powerful standard module. Utilizing 36 specially processed single-crystal solar cells, the M55 is capable of producing 53 Watts at over 3 amps. Charging voltage is achieved in as little as 5% of full sunlight resulting in power being produced from early to late in the day. The principle specifications of the M55 are given in Table 3-1.

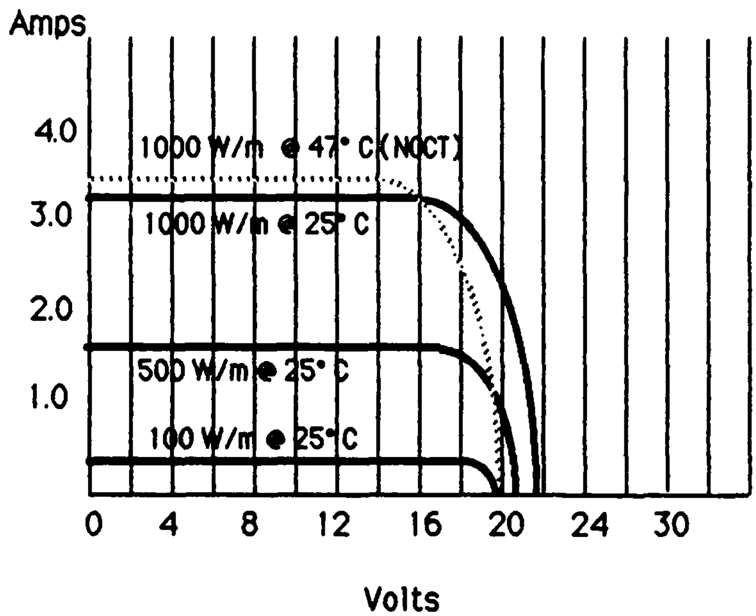
TABLE 3-1. SPECIFICATIONS, ARCO SOLAR MODEL M-55 MODULE

Power Specifications[a]	
Power (typical ± 10%)	53.0 Watts
Current (typical at load)	3.05 Amps
Voltage (typical at load)	17.4 Volts
Short Circuit Current (typical at load)	3.27 Amps
Open Circuit Voltage (typical at load)	21.8 Volts
Physical Characteristics	
Length	50.9 in/1293 mm
Width	13 in/330 mm
Depth	1.4 in/36 mm
Weight	12.6 lb/5.7 kg

[a]Power specifications are at standard test conditions of: 1000 W/m^2, 25°C cell temperature and spectrum of 1.5 air mass.

Figure 3-2 illustrates the variation in module characteristics with temperature and insolation. Note that the open-circuit current voltage varies inversely with cell and ambient temperatures, and the short circuit current varies directly with insolation and temperature. Also note that the voltages are relatively insensitive to insolation. A PV module (cell or array) can operate anywhere along its I-V curve. This is determined at any time by insolation and cell temperature. The short circuit current is shown on the current axis at zero voltage. As the load resistance increases, causing the voltage output of the cell to increase, the current remains relatively constant until the "knee" of the curve is reached. Then, the current drops off quickly, with only a small increase in voltage, until the open-circuit condition is reached. At this point, the open-circuit voltage is obtained and no current is drawn from the device.

The power output of any electrical device, including a solar cell, is the output voltage times the output current under the same conditions. Thus, if the module operates at short-cicuit or open-circuit conditions, no power is produced.



The IV curve (current vs. voltage) above demonstrates typical power response to various light levels at 25° C cell temperature, and at the NOCT (Normal Operating Cell Temperature), 47° C.

Figure 3-2. The IV curve for the ARCO Solar M-55 solar electric module.

3.3.2 Maximum Power Point Tracking

The maximum power point (MPP) is the best combination of voltage and current. This is the point at which the load resistance matches the solar cell internal resistance.

The maximum power tracker circuitry is usually incorporated into the PCU which is placed between the array and the load. The tracker samples the PV output periodically (usually about once every 15 seconds) and

changes the operating voltage point in increments (about 4 V) and compares it to the previous output current reading (AC). PV output power is generally measured by multiplying the PV voltage and current readings together.

If the comparison has indicated that the power has increased, the next voltage step will be in the same direction. If the power has decreased, then the voltage will step in the opposite direction. Thus, the PCU continuously tracks the MPP.

3.3.3 Bypass Diodes

The M55 modules are equipped with bypass diodes to protect the cells in the module (or bypassed group) by limiting the reverse biased voltage that can appear across a shaded cell to the voltage generated by the remainder of the cells in the bypassed group. A solar cell is an electrical rectifier; it passes current in only one direction. In the dark, the silicon solar cell acts like any silicon diode rectifier. If one cell in a series string of cells is shaded (leaf or tree shading), the current through the string stops immediately and the sum of all of the open-circuit voltages of all of the other cells shows up across the shaded cell. If the cell is not strong enough it will break electrically and begin to conduct. Thus, the bypass diode is needed to prevent this from happening.

3.3.4 Power Conditioning Unit

The power conditioning unit (PCU) is an integral part of any solar PV system and is required to perform many operations to safely control and deliver the maximum amount of electrical energy from the PV array. The PCU must be utility-interactive (U-I) with features such as maximum power-point tracking, transformer isolation between AC and DC systems, and self-protection.

The PCU DC input must be 2 kW or higher to meet the needs of the load requirements. Finally, the PCU must be readily available for purchasing and delivery. The Photoelectric, Inc. Model SI-3000 Solar Inverter was selected on the basis of performance specifications, costs, and because it meets the above requirements. Table 3-2 lists some of the principle specifications of the SI-3000 PCU. Some of the detailed operating specifications are included later in this report.

The PCU is responsible for safely and effectively controlling the solar PV system. It responds automatically to the availability of power from the array and determines where the energy goes. It turns on when the insolation level is high enough, automatically tracks the MPPT voltage under variable weather conditions, and turns off when insolation is unavailable. At the same time, it protects itself and the system during abnormal conditions and prevents dangerous shocks hazards from

occurring. However, the PCU cannot operate without utility supplied power. The SI-3000 also has a convenient display which can show: Input & Output Voltage, Input & Output Amps, and Output Kilowatts, Kilovars, and Kilowatt-Hours (Ref. 1).

TABLE 3-2. PRINCIPLE SPECIFICATIONS OF THE SI-3000 PCU

Features

AC Output (Utility Inter-Tie): Operates in a nominal 120/240 Vac, single phase utility system with an operating range of 208 Vac to 254 Vac.

DC Input (Array Output): 48 Vdc nominal; operational from 37 Vdc to 57 Vdc. Input of 0 to 80 Vdc is not damaging.

Rated power: 3000 Watts

Reactive current: Limited during steady state operation from 1/8 load to rated load, to between 0.95 lag to 0.95 lead at the interconnection point to the utility.

Harmonic current distortion: Less than 5 percent RMS 1/4 to full power.

Ripple: The peak to peak array current does not exceed 10 percent of the nominal input current at rated power.

Frequency: The utility power frequency can vary between 58 and 62 Hz.

Efficiency: From array input to utility connection point, the efficiency exceeds 93 percent at full load and 95 percent from 1/4 to 3/4 load.

Ambient operating temperature: 0 to 45 degrees C Non-operating: -40 to 70 degrees C.

Physical characteristics:
Dimensions: 14.25" x 12.5" x 8.0" approximate
Weight: 38 lbs.

3.3.5 Battery Controller (for stand-alone design)

The battery controller used is the Balance of System Specialists, Inc. Power Control Series model #8104820 rated at 48 volt, 20 amp. This unit protects against incorrect wiring of panels or batteries. It features temperature compensation, low voltage detection, lightning protection, and diverts all of the array power directly to the power inverter when the batteries are fully charged. It is also equipped with its own meters for PV system monitoring (Ref. 2).

3.3.6 Power Inverter (for stand-alone system)

The power inverter selected is the Dynamote Model #UXB 6.0. This is a sine wave inverter, not a square wave inverter. It runs competely on DC battery power and requires no AC power for operation. It also has its own built-in frequency regulation circuitry. Some of the principle features are listed in Table 3-3. The surge power rating is the maximum power available to start larger motors, such as the air conditioning compressor pump (Ref. 2).

TABLE 3-3. PRINCIPLE FEATURES OF THE DYNAMOTE *UXB INVERTER

Features		
Output watts at 120 VAC	:	6,000 W
Surge capability AC watts	:	15,000 W
Input volts DC	:	48 VDC
Input voltage range DC	:	42-60 VDC
Shipping weight lbs.	:	40 lbs.
No-load power draw (W)	:	0.5 W

3.3.7 Storage Batteries

The storage batteries used for the stand-alone design are I.B.E. single cell 2 volt batteries Model *75N33 rated for 1476 ampere-hours. These batteries last up to 25 years and can be wired together in a convenient 6-pack for 12 volt power. They are deep-cycle batteries and weigh approximately 200 pounds apiece (Ref. 2).

3.4 DISCUSSION ON BATTERIES

For most solar photovoltaic systems, some type of storage medium is needed to store excess energy generated by the array during the day. Many systems have been proposed and developed for the storage of electrical energy. They include batteries, capacitors, flywheels, pumping water uphill, converting water to hydrogen and oxygen, and pumping air into high pressure storage tanks. By far, the most popular and practical of these methods for the average small user of photovoltaic arrays is battery storage. The discussion which follows will briefly describe the types and characteristics of storage batteries available for solar applications today.

A storage battery can be used to store electrical energy on a short term basis. The efficiency of a storage battery, energy retrieved divided by the energy deposited, decreases slowly with storage time. Thus, energy generated and stored during the summer months would be lost due to battery self-leakage before it could be used for the low solar power periods of the wintertime. However, energy stored during a sunny day can be stored and used during the night or on a cloudy day.

There are five basic battery characteristics and concerns that must be understood in order to use a battery properly with a photovoltaic array: storage capacity (C), storage efficiency, state of charge, operation procedures, and maintenance.

A storage battery can be expected to last from 5 to 25 years, with its storage capacity depending on the number of charge/discharge cycles, depth of discharge, and operating temperature. In most solar PV systems, storage batteries must be able to be charged and deeply discharged on a daily basis for 10 to 20 years.

Automotive batteries, on the other hand, are designed to start something and then be quickly recharged by the alternator before they are significantly discharged. An automotive battery can only be deeply discharged about 20 times before it becomes completely useless. A battery is said to have lived its useful life when its storage capacity drops below 80% of the nominal capacity.

A battery's efficiency can be measured in two ways: ampere-hour (Ah) and watt-hour (Wh). The capacity C gives the number of Ah stored in the battery. The Ah efficiency gives the ratio of the number of ampere hours that can be supplied by the battery to the number put into the battery. The Wh efficiency equals the amount of watt hours flowing from the battery over the amount put into the battery. The Wh efficiency is normally lower than the Ah efficiency due to the presence of an internal battery resistance. Typical values of efficiencies for a new battery under ideal conditions are 90 to 95 % for Ah efficiency and 60 to 85 % for Wh efficiency (Ref. 3). Battery efficiency and capacity decrease with time because of a self-discharging current within the battery. For a typical battery the self-discharge rate doubles for every 10° C drop below room temperature.

A battery's state-of-charge (soc) must be monitored at all times. This determines the amount of remaining energy available from the battery.

Voltage regulating devices are necessary for the proper operation of the batteries to prevent overcharging or excessive discharging. Permanent damage can occur to a battery if it is charged too fast and/or too long. Low-level trickle charging, however, can continue indefinitely since it offsets the battery's self-discharging current.

Finally, proper maintenance is essential to ensure the longest possible battery life.

The fluid levels within the batteries must be kept high enough to prevent the plates inside the battery from becoming exposed to air. Exposure results in permanent damage to the plates. The batteries should be kept clean to prevent corrosive slime from building up on and around the battery terminals and top surface.

Certain safety precautions must be strictly followed when using lead-acid batteries. The battery storage room must be well ventilated to prevent the highly explosive hydrogen gas, generated during battery gassing, from concentrating in high levels. Also, the extremely corrosive sulfuric acid inside the batteries must be prevented from spilling. Battery racks are used to keep the batteries off of the floor to make cleaning and maintenance easier. The cables that interconnect the battery terminals should be heavy and the connections should be very tight.

For the designs given in this report, the storage batteries, if needed, will be placed on steel racks located in a covered cement trench outside of the house or business and below ground level. Ventilation is provided by a low-power exhaust fan which runs continuously, and a drainage pipe is installed in the bottom of the trench to allow water used for cleaning to escape.

There are many different varieties of storage batteries available today, with new experimental types still being tested. The two most popular types are lead-acid and nickel-cadium (Ni-cad). Nickel-cadium batteries were developed around the turn of the century but not commonly used until the 1950s. The main advantages of the Ni-cad battery are long life and reduced maintenance requirements. The main disadvantage, and the reason why lead-acid batteries are more widely used, is the high cost per ampere-hour of capacity. Ni-cad batteries are mainly used for small applications.

The main advantages of the lead-acid batteries are the good Wh efficiency (typically between 70 and 80 %), a relatively low cost, and the small self-discharge rate (Ref. 3). Disadvantages include low values of charging and discharging currents and the necessity for protection against overcharging. Lead-acid batteries are used for design purposes in this report because of their wide use, low cost, and availability.

3.5 SITE CONSIDERATIONS

The site of the solar village will be located about 30 to 50 miles away from the Phoenix metropolitan area in an isolated area not currently serviced by commercial electric power companies. This location allows us to use the meteorological data for the Phoenix area with very little or no variation. Also, the cost of the solar PV system can be compared with the cost of building a new transmission line, substation, and other electric power related equipment needed for the new distribution system for the utility backup design. This is discussed in a later section.

The site of the solar village would most likely, but not necessarily, be located on state owned land because the state could sell or lease the land at a favorable price to show support for the project. The state also has plenty of land available for a site and could offer additional incentives for developers to build the village. If the village was constructed on private land, the costs presumably would be higher. For purposes of cost analysis, the price of the land is not included, assuming it would be the same for any design of the solar village.

Realistically, the site of the village must have a source of water and be located relatively close to an existing highway. Building a new road of any distance would add tremendously to the cost of the village.

Also, another area which mustn't be overlooked is the impact the village would have on the environment. Of course, one advantage of solar

power is that it doesn't create any pollution, at least not after the components have been made. However, many enviromental studies must be done to ensure the natural habitat and wildlife are protected and encouraged to live undisturbed as much as possible. This is for people's benefit as well.

Table 3-4 gives the meteorological data for the Phoenix area,

TABLE 3-4. CLIMATIC STATISTICS FOR PHOENIX, ARIZONA

Month	Clearness Index Daily Average (Dimensionless)	Dry Bulb Temperature Daytime Ave. °C	Dry Bulb Temperature Daily Ave. °C	Wind Speed Daily Ave. (m/s)
JAN	0.610	13.4	10.8	2.4
FEB	0.652	15.5	13.1	2.7
MAR	0.679	18.7	16.2	3.0
APR	0.743	22.9	20.4	3.2
MAY	0.765	28.4	25.7	3.2
JUN	0.757	32.7	30.8	3.2
JUL	0.701	35.5	33.6	3.3
AUG	0.698	34.2	32.2	3.0
SEP	0.706	31.7	29.1	3.0
OCT	0.687	25.6	22.6	2.7
NOV	0.640	18.2	15.4	2.5
DEC	0.606	13.8	11.1	2.4
YEAR	**0.687**	**24.3**	**21.8**	**2.9**

(Ref. 4)

3.5 SYSTEM CONFIGURATION

3.5.1 PV Array

The PV array consists of a number of solar modules interconnected in a series-parallel configuration which is compatible with the PCU. First, the modules are connected in series to establish the required voltage. Then the series strings are connected in parallel to establish the required current needed to meet the power requirements.

The modules chosen, ARCO Solar's M55 have a maximum power voltage of about 17.4 V with a peak power of 53 W. Their area is 0.427 m^2.

If each string of modules, or source current group (SCG), consists of 3 modules, the highest voltage possible (worst case) can be found as shown below. At open circuit conditions of 1000W/m^2 and 47 °C ambient temperature the voltage would be:

$$V_{max} = [21.8\ V + 0.0024\ V/{}^\circ c\text{-cell}(47^\circ C \times 36\ \text{cells/module})]3\ \text{modules}$$

$$= \underline{77\ Vdc}$$

This is above the operating range of the PCU, but safely below its specified 80 Vdc stand-by mode voltage.

To determine the number of modules needed to provide the 3 kW of power suitable for the residential house, a design method presented by Ref. 5 will be utilized.

First, determine the annual average daytime temperature where the daytime is defined as beginning at 0600 hrs and ending at 1800 hrs. From the table in Ref. this temperature is shown to be

<u>24.3 °C (76 °F).</u>

The annual average cell temperature is 49.3 °C at the nominal peak insolation.

Thus,

$$T_{cell} \text{ (Annual, daylight average)} = 0.025I + 24.3 = 49.3\ ^\circ\text{C}$$

where I = Nominal peak insolation = 1000 W/m^2.

Referring to ARCO's Solar M55 module specifications, the efficiency and output is estimated as follows:

at T_{cell} = 25 °C, and P_{out} = 53 W/module (specified)

$$\text{module} = (53\ \text{W}/[(1000\text{W/m}^2)(0.33)(1.293)\text{m}^2])$$

$$= \underline{12.42\ \%}$$

Thus, at

Tcell = 49.3 °C

module = 0.1242[1 - 0.004(49.3-25)]

= 11.2 %

and P_{out} = 0.1121[(1000 W/m^2)(0.33)(1,293)m^2]

= 47.8 W/module

assuming mismatch losses of 10%, the average module output in the array will be:

$$P_{out(average)} = 0.9 \times 47.8 \text{ W/module} = \underline{43.1 \text{ W}}$$

Therefore, for the average daytime temperature and nominal peak insolation conditions, the desired number of modules is

No. modules = 3000 W/(43.1 W/module)

= 70 modules

Although this calculation says 70 modules should be used, the design will consist of 72 modules because residential PV systems reported by the manufacturers tend to have less peak output than reported.

Also, the annual average daytime temperature used in this design is lower than the annual average for mid-day hours corresponding to peak insolation. Thus, using 3 modules per SCG, the array consists of 3 modules/SCG x 24 SCGs = 72 modules and covers an area of 31 m^2.

The relationships between PV cells, modules, source circiut groups and the PV system array are illustrated in figure 3-3. Each entity is represented in the figure by the appropriate symbol. As shown, there are 36 cells and 1 bypass diode per module, 3 series-connected modules per source circuit group, and 24 paralleled source circuit groups in the array.

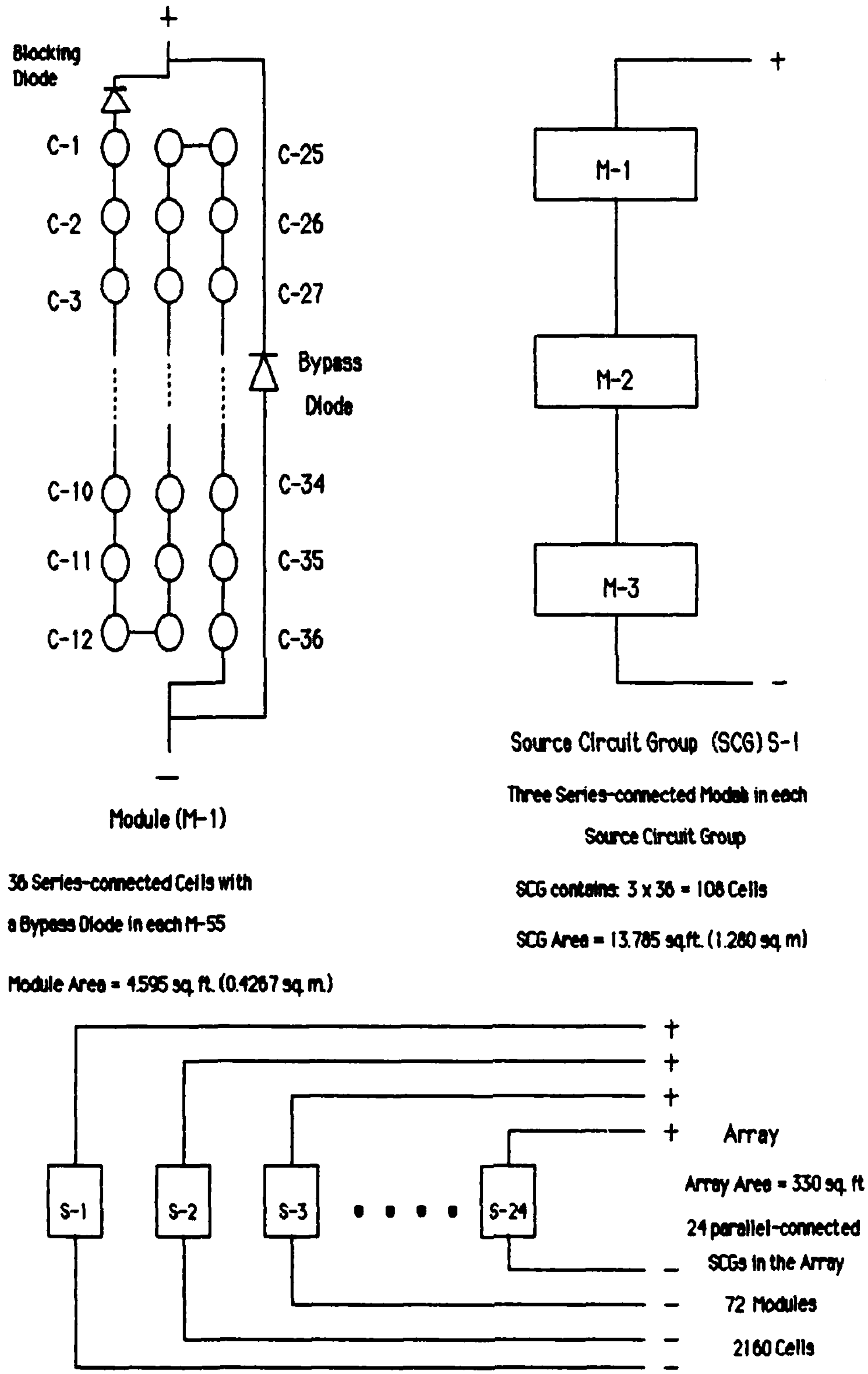


Figure 3-3. An illustration of the PV array configuration.

3.5.2 Array Protection and Troubleshooting

Because of the possibility of a short or open circuit in the array, certain design features are needed to protect the array and help locate the problem. A short or open circuit can seriously affect the operation and efficiency of the array and even damage some of its components. Locating the trouble can also be time-consuming, expensive, and frustrating.

Figure 3-4 shows the wiring diagram of the array including the protection and testing devices. The basic scheme involves connecting the modules in series per branch and then having four branch circuits connect into what is called here a branch circuit cluster. If there are 24 branch circuits, then there are six branch circuit clusters. All of the six branch circuit clusters then run into a major junction box where they are connected to blocking diodes and a parallel busbar. In addition, each branch circuit cluster will have a pair of varistors from the positive and negative wires to ground to protect against static charge buildup and induced voltage spikes. The voltage across each branch circuit cluster can be measured by using a portable voltmeter at the test points in each branch circuit.

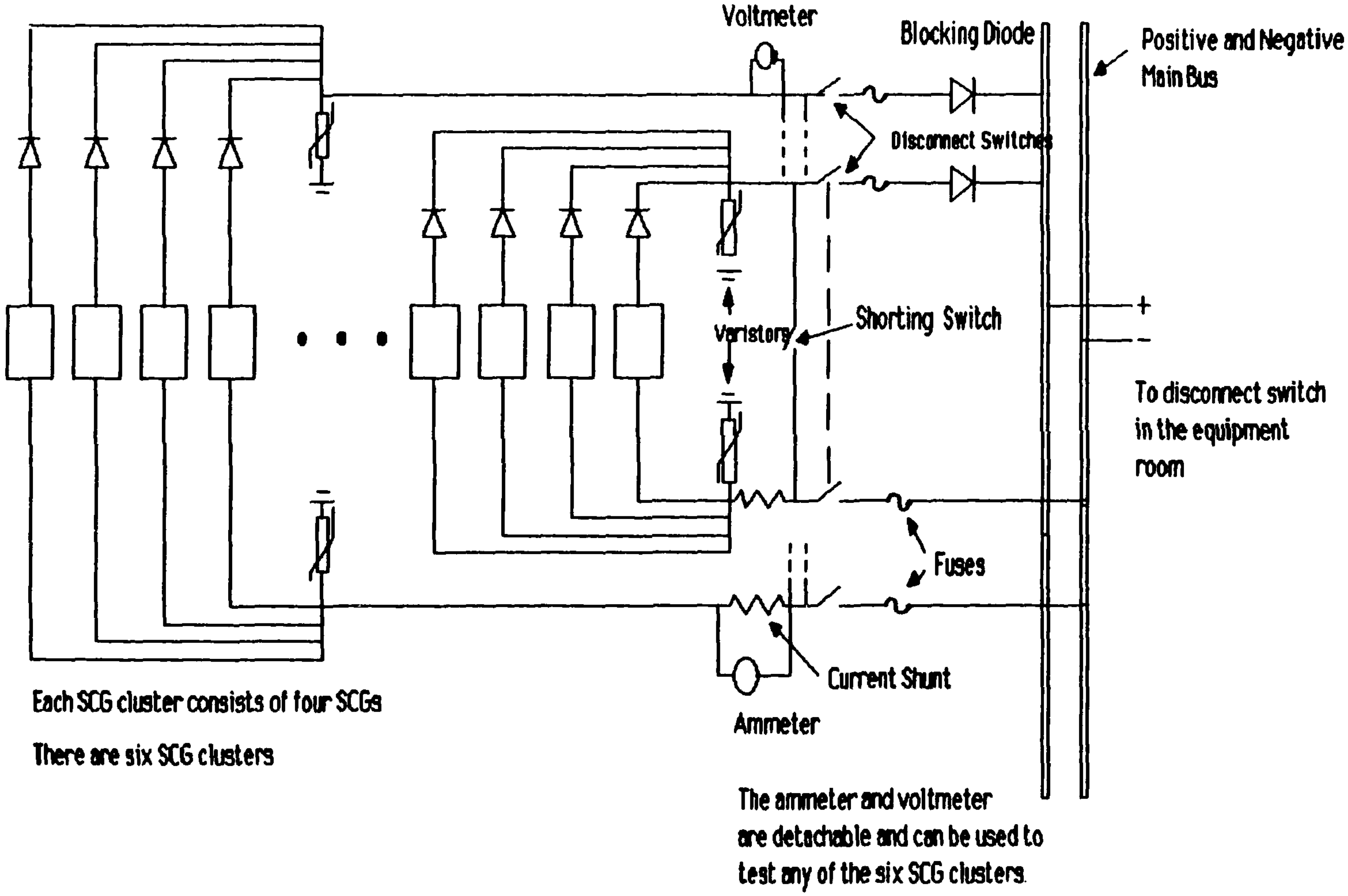


Figure 3-4. Schematic Illustration of the PV array wiring

The current in the branch circuit cluster can be done by using a current shunt and an voltmeter. The shunt's resistance (approximately 100 mΩ) is kept small to keep the losses down. The current is found by dividing the voltage across the shunt by its resistance. This technique is safer since the main branch current cluster flows through the large diameter branch wiring instead of the operator held voltmeter.

The shorting and disconnect switches in the power lines coming from the branch circuit clusters are used for troubleshooting. By closing the shorting switch, the positive and negative leads are shorted, and the ammeter will indicate the short-circuit current. This switch is a single-pole switch. The disconnect switch is a double-pole switch and, when open, is used to isolate the branch circuit cluster and to measure the open-circuit voltage. Under normal operating conditions, the shorting switch will be open and the disconnect switch will be closed.

Diodes and fuses are used to prevent reverse current from flowing back into the array, particularly at night when the array has no output voltage. Also, if a short occurs in one of the branch circuits, it will draw current from the other branches unless diodes are there to prevent it. The diode is positioned in such a way as to allow the current to flow from the array to the house but will prevent any current from flowing back into the array from battery storage or from the utility. The diode also prevents the PCU (and battery) inputs from being shorted when the shorting switch is closed.

DC fuses are used as a backup in case the blocking diode or varistors

fails. A fuse is placed in both the positive and negative leads. Should the blocking diode fail, the fuses will open to prevent reverse current from flowing into the array.

If the array is hit by a lightning strike and the varistors are unable to handle the large amounts of current, the fuses will open to prevent this damaging current from going into the PCU. Hence, the fuses must have a very fast response time (ref. 6).

All of the branch circuit clusters are connected in parallel to a main busbar (+ and -) made of solid copper. The leads from the main array bus are connected to a fused disconnect switch and then to another pair of varistors from the positive and negative leads to ground. A cable is used from the negative bus to ground to carry large currents caused by lightning strikes. The wires then are connected to a disconnect switch on the DC side of the PCU and then to the PCU itself. As mentioned earlier, the PCU will automatically monitor the input and output current and voltage.

A simple block diagram of the array wiring is shown in figure 3-5 to help clarify the location of the array components.

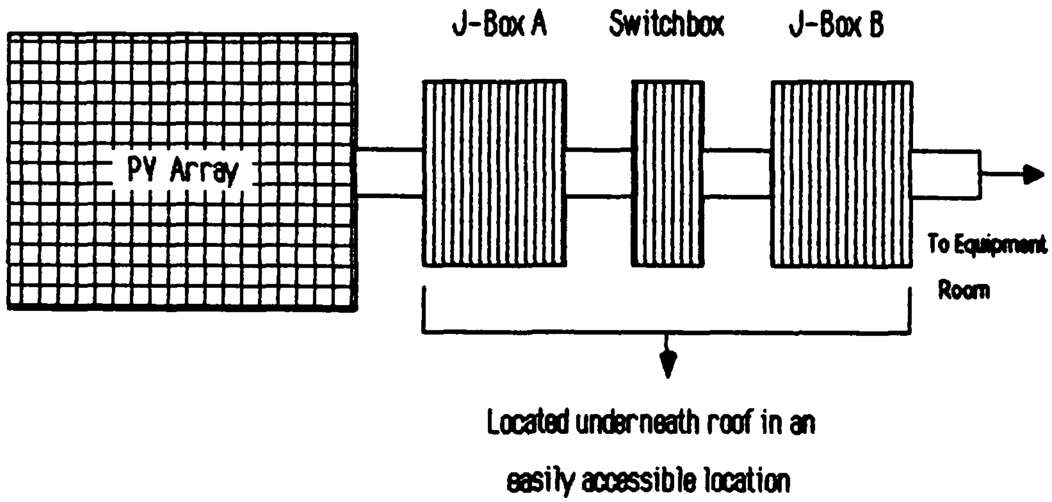


Figure 3-5. Block diagram of array wiring

Because of the integral mounting scheme used for the array and described later in this report, the individual modules are easily accessible for testing, repair, and replacement if neccessary.

3.5.3 Interfaces

The PCU is the interface between the DC output of the PV array and the AC power panel of the system. It controls the operation, status, and characteristics of the solar PV system. The PCU operates within its contraints to turn the system on and off, load the array to its most

efficient operating point, and provide protection and isolation between the array power (DC) and utility power (AC) when applicable. The operating characteristics will be discussed in a later section. A physical description of the PCU interface is presented here.

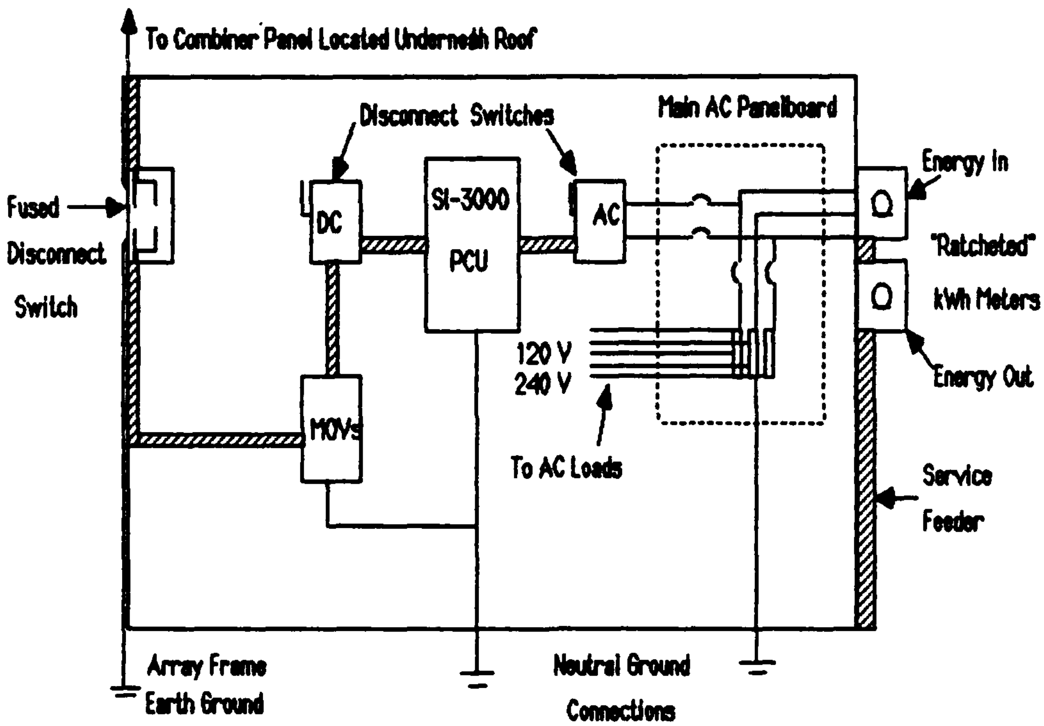


Figure 3-6. Block Diagram of Equipment Room - Utility Inter-tie.

Figure 3-6 is a schematic diagram of the PCU interface with the DC and AC parts of the system with utility inter-tie and no battery storage. As determined earlier, the array consists of 72 solar PV modules with

24 parallel strings of 3 modules connected in series. These 24 strings or SCGs connect in a source combiner box located in an accessible position near the array. Two conductors lead out of the combiner box, run through a 1-inch steel conduit, and connect to a 100 amp non-auto breaker such as the Square D Catalog No. QO2000NAS. This breaker should be mounted near the PCU to allow for a service disconnect for the PV array. A 1-inch steel conduit is mounted on the bottom of the PCU and connects to the breaker box.

The + array wire must connect to the + (BLACK) PCU terminal while the - array wire must connect to the - (WHITE) PCU terminal. The negative terminal is connected to the PCU frame internally. A large frame stud is used as a connection to an external earth ground with a wire of sufficient size to carry the array short circuit current. For this design, a #8 AWG ground wire is sufficient according to Art. 250-95 of the National Electrical Code (NEC) (Ref. 7). All conductors are assumed to be copper.

The array wire size is dependent on the length of the runs and should be sized large enough to keep voltage drops low. For a full power current of 60 Amps, a minimum wire size of #6 AWG is used for short runs such as between the array disconnect and the PCU. Conductors from the array to the disconnect will be sized #4 AWG or larger depending on the distance. For example, the run from the combiner box to the breaker disconnect is approximately 50 to 60 feet which would require a conductor of size #4 AWG.

On the AC side of the PCU, the nominal utility inter-tie voltage is 240 Vac 60 Hz with grounded neutral. A Double Pole 20 amp AC Toggle switch, such as Hubbell or Leviton Catalog No. 1122, is mounted near the PCU. This switch provides a disconnect for the PCU from the AC side. AC line connection terminals are located inside the PCU. The AC disconnect switch then connects to the main AC power panel where utility power interconnects after passing through a watthour meter (Ref. 1).

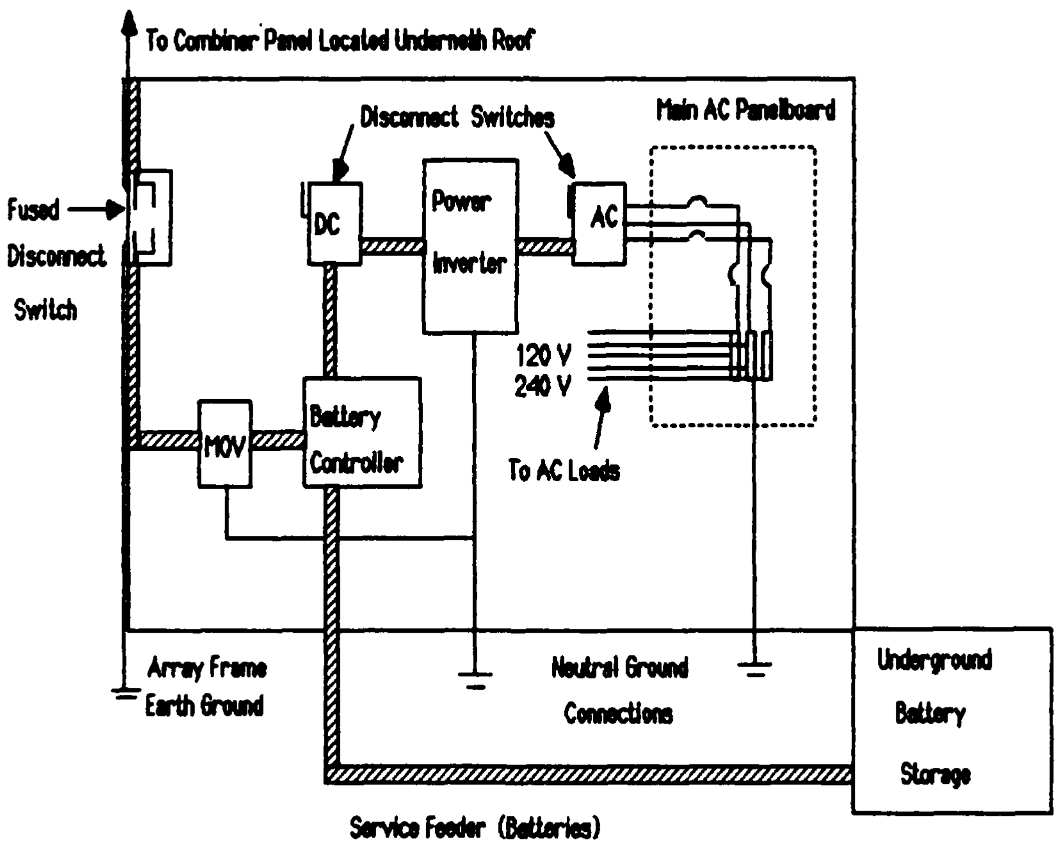


Figure 3-7. Block Diagram of the Equipment Room - Battery Storage

Figure 3-7 shows a similar schematic diagram as that of figure 3-6 only this time the system has battery storage and no utility inter-tie. Here, the batteries are connected in parallel with the solar PV array ahead of the PCU. A power control unit is needed to keep the batteries from being discharged below design limits and from overcharging. It works with the power inverter unit to allow for the best possible use of array current. When the array is producing more power than the load demand, the excess current is used to charge the batteries. The battery power can then be used at night or on cloudy days.

The Balance of System Specialists, Inc. model No. 8104820 48 Vdc/20 Amp power controller is used for this design. Because of the array size and battery storage requirements, three controllers are needed for each house to handle to the full load current of 60 amps. At approximately $400 apiece, this significantly adds to the cost of supplying battery backup power.

The 12 VDC storage batteries are connected series-parallel in an array to provide an output voltage of 48 VDC for the power inverter. Again, for a full power current of 60 amperes, the wires from the battery array to the battery controller should be sized at least #4 AWG. The cables connecting the batteries together should be sized #4 AWG also. This will reduce the voltage drop from the array to the battery controller.

Voltage Drop = (60 A)(100 ft)(0.0614 Ω/100 ft) = 3.68 volts for *4 AWG

This equates to a (3.68 V/48 V)100 = 7.67 % voltage drop which is quite a bit although still well within the minimum operating voltage of 38 VDC for the PCU or 42 VDC for the power inverter. However, the power loss is greater.

Power Loss = I^2R = $(60\ A)^2(0.0614)$ = 221 Watts for *4 AWG

A better choice is a *2 AWG cable where the voltage drop is,

Voltage Drop = (60 A)(100 ft)(0.0382 Ω/100 ft) = 2.29 volts for *2 AWG

which equates to a (2.29 V/48 V)100 = 4.78 % voltage drop.

The power loss for this size cable is

$$\text{Power Loss} = (60\ A)^2(0.0382) = 137\ \text{Watts}$$

This is considerably less than the 221 watts for the *4 AWG cable.

A single-throw DC disconnect switch fused for 100 amps is placed betwen the battery array and the controller.

3.5.4 Battery System Sizing and Calculations

Using the results from the load survey, calculations can be made to determine the size of the battery storage banks for two of the three different solar designs: stand-alone and interconnection between stand-alone systems. The economic restrictions of having battery storage with utility tie-in will be discussed later. The design procedure, outlined in reference 3, will be followed here.

The first step here is to determine the daily energy consumption, called U_m, and assume for the sake of simplicity that it's constant throughout the year. The design is based on the minimum number of modules necessary to operate the system. The peak power P_c of a PV array is the power produced under standard illumination corresponding to a power density of 1 kW m^{-2} and when the array is loaded to its maximum power point. The energy output (U_{out}) of an array with a peak power P_c resulting from an incident solar energy H (in kWh m^{-2}) is found by multiplying P_c by the number of hours (h) of peak insolation.

Thus,

$$U_{out}\,(\text{kWh}) = Pc\,(\text{kW}) \times h$$

Realizing that the incident solar energy H is equivalent to a number of h hours under peak insolation i.e. $H\,(\text{kWh m}^{-2}) = h \times 1\ \text{kW m}^{-2}$

then

$$U_{out}\,(\text{kWh}) = P_c\,(\text{kW}) \times [H\,(\text{kWh m}^{-2})/1\ \text{kW m}^{-2}]$$

If the yearly average of the daily solar insolation in the plane of the modules equals H_{ave} (kWh day^{-1} m^{-2}), then the above equation indicates the minimum number of peak watts necessary to compensate a daily energy consumption of U_m (kWh day^{-1}). So,

$$P_c\,(\text{kW}) = [U_m\,(\text{kWh day}^{-1}) \times (1\ \text{kW m}^{-2})]/[H_{ave}\,(\text{kWh day}^{-1}\ \text{m}^{-2})]$$

In actual operation the array is not always loaded to the maximum power point, and other variables are present which cause losses in the system. Several additional factors are introduced to represent the efficiencies of the system. N1 is a matching efficiency caused by the difference between the battery I-V curve and the optimum power point. Taking the variations due to temperature into account, a typical value would be around 85%. N2 is the ohmic losses in the interconnections and wiring and due to dust and aging, typically 85%. N3 is the charging-discharging efficiency of the battery and can be written as

$$N3 = xN_{bat} + (100-x)$$

where N_{bat} is the intrinsic battery efficiency, typically 70 to 85%. Taking these factors into account, the minimum number of peak watts becomes

$$Pc = [Um \times 1\ \text{kW m-2}]/[N1\ N2\ N3 \times Have]. \qquad \text{EQ. 1}$$

Now, to calculate the battery size it is normal to assume a sinusoidal

variation of the energy production U during the year as shown below.

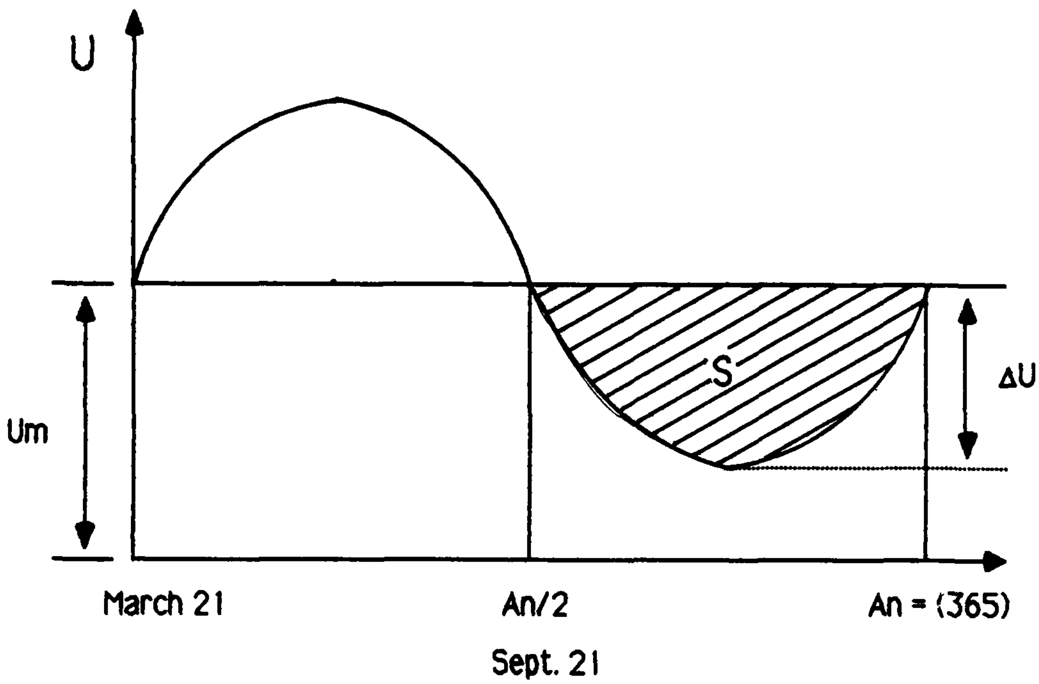


Figure 3-8. Variation of the generated power over the year for a system with mimimum module size.

If H_{ave} is the solar energy density on the modules (e.g. in kWh $day^{-1}m^{-2}$), then U (in kWh day^{-1}) will be given by

$$U = P_c \times N1 \times N2 \times N3 \times H_{ave} \ (kWh\ day^{-1}\ m^{-2}).$$

If P_c is chosen such that the average value of U equals U_m, then it follows the energy to be stored is

$$C = \int^{365/2} \Delta u \sin(2\pi t/365)dt = (365\,\Delta u/\pi)\ \text{kWh}$$

where $\Delta u = N1 \times N2 \times N3 \times Pc(H_{max} - H_{ave})$. EQ. 2

A multiplying factor of 1.25 is used in the above equation to take into account weather variations from year to year. Another multipying factor of 1.25 represents the limitation of the state of charge to no less than 25%. The equation for battery sizing then becomes

$$C = (1.25)^2 \times (365\Delta u)/\pi\ \text{kWh} \qquad \text{EQ. 3}$$

Equations 1, 2, and 3 can now be used to design a system with a minimum number of modules.

For the stand-alone design, the load requirement is 60 kWh/day as it was for the first procedure. The array inclination is approximately 20°. The battery matching efficiency N1 is 85%, the interconnection and wiring efficiency N2 is 85%, and the charging-discharging efficiency N3 is taken to be 90%. Table 3-5 below gives the incident solar energy intensity levels H for the array at a 20° angle from horizonal for all of the months of the year are given.

TABLE 3-5. INCIDENT SOLAR ENERGY INTENSITY LEVELS (20° TILT)

Month	H (kWh/m^2-d)	Month	H (kWh/m^2-d)
January	4.32	July	7.51
February	5.33	August	7.25
March	6.38	September	6.85
April	7.65	October	5.90
May	8.19	November	4.74
June	8.18	December	4.07
	Year	6.37 kWh/m^2-day	

From Table 4-5, $H_{ave} = 6.37$ kWh m^{-2} day^{-1}

and $H_{max} - H_{ave} = 1.82$ kWh m^{-2} day^{-1}.

EQ. 1 now gives $P_c = (60)/[(0.85)(0.85)(0.9)(6.37)] = \underline{14.48\ kW}$

Δu follows from EQ. 2 $\Delta u = (0.85)(0.85)(0.9)(14.48)(1.82) = \underline{17.14}$

and EQ. 3 gives the necessary battery capacity,

$$C = (1.25)^2[(365)(17.14)/\pi] = \underline{3111 \text{ kWh or } 3.111 \text{ MWh}}$$

For a 48 Vdc system, this works out to 3111 kWh/48 Vdc = <u>64,800 AH</u>

This is a large amount of energy and requires a large battery array as well as a large solar array. For the residential solar PV design of 72 solar modules, which produce a maximum of 53 watts each, the peak power the array can produce is

Array peak power = 72 modules x 43.1 watts = <u>3.103 kW.</u>

This is over 10 kW less than what was estimated. If the system was designed to produce a maximum of 14.5 kW, it would require:

Number of modules required = 14.5 kW/43.1 W per module = <u>336 modules</u>

The cost of the modules alone @ $343/module would be $115,248 which is economically prohibited. Also, the cost of supplying enough batteries to store the necessary number of ampere-hours (64,000 AH) would be approximately $14,960. This gives a total cost of the modules and batteries alone of $130,208.

3.5.4 Installing the Solar Array

Before the solar array can be installed, a variety of factors must be considered and careful planning done. For instance, the array must be located in an unsheltered location where the sunlight won't be blocked, and the supporting structure must be able to withstand severe weather conditions, particularly wind, over the lifetime of the array (about 20 to 25 yrs). The array should also be kept as cool as possible since the solar cells operate more efficiently at lower temperatures. Roof mounted arrays should be weathertight and physically attractive.

Finally, the cost of the mounting structure must be kept as low as possible.

While most PV systems currently in operation require little maintenance, a system will eventually need to be serviced and sometimes repaired. Thus, it is important that the array is fairly easily accessible for cleaning and for troubleshooting and replacement of modules and components as needed. In the Phoenix area, dust is a major problem where even a thin film of it can reduce the amount of sunlight reaching the solar cells, thus reducing the output current and power of the array.

All of the designs in this report involve mounting the array on the south facing roofs of the buildings in the solar village. There are four basic photovoltaic-module mounting schemes which have been established by industry and research centers: rack, standoff, direct, and integral (Ref. 6). A brief description of each scheme follows.

Rack Mount

When an array is installed on a horizontal surface such as the ground or a flat roof, a tilted support frame or rack is used to position the array at the best angle for solar insolation i.e. power output. Most racks are made of steel while others consist of wood. Racks situated on the ground must be thoroughly secured, usually by being mounted on a solid concrete foundation to prevent high winds from blowing the array away. The racks are usually assembled in rows which are set apart from each other to prevent one row from casting a shadow on the row behind it. This arrangement provides easy access to the front and rear of the modules for easy testing, repair, and removal.

It also keeps the modules as cool as possible because the air can easily circulate around the array transferring off the heat generated. However, the cost of the rack mount scheme is usually higher than the other methods because of the extra materials and labor needed to construct and support the array. Also, roof mounted module racks have a very low esthetic appeal because they clash with the enviroment by giving a building a "porcupine" look.

Standoff Mount

Basically, a standoff roof mounting scheme involves putting the modules on a support structure which itself is mounted over but stands

off from a conventional slanted shingle roof by a few inches. The supporting frame is mounted onto the roof, thus requiring careful weather sealing at those points where the roof is penetrated. Because of the ventilation on both sides of the array, the modules can operate more efficiently because of lower temperatures.

There are different types of standoff mounting schemes, some of which make the removal and maintenance of the modules fairly simple. But here again, the extra materials and labor needed tends to drive of the cost of the array. Also, wind tunneling can occur underneath the array, causing a fire to spread rapidly unless measures are taken to prevent it. The standoff mount is generally used to put a new array on a building where the roof is already in place.

Direct Mount

The direct mount involves replacing the asphalt shingles on a conventional roof with solar cell shingles. The solar shingles are mounted directly on the roof felt, usually in an overlapping pattern to help make a weathertight seal. While this method result in a lower cost because of fewer materials needed, the array is more affected by higher operating temperatures. This occurs because there is no air circulation between the array and the roof. Thus, operating temperatures are about 20° C higher than with the rack, standoff, and integral mounting schemes. This can result in cell cracking and material degradation.

Integral Mount

Because the houses in the Solar Village will be new, an integral mount of the solar panels will be used. Here, the solar cell modules are mounted directly on the roof rafters and sealed with a gasket or caulking. Metal flashing is used to cover cracks between the modules. The design of the roof should take into consideration temperature expansion and contraction of the materials. (See figure 3-9).

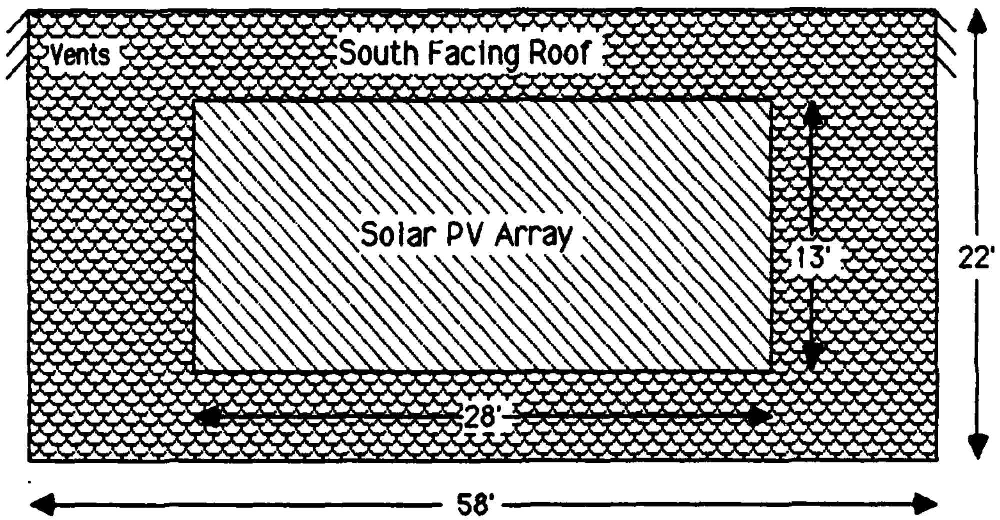


Figure 3-9. Schematic of solar PV Array Roof Location

To keep the operating temperatures of the modules as low as possible, no insulation is put behind the modules. Rather, the ceiling of the house is heavily insulated. Also, because metal and glass are poor insulators and good conductors of heat, attic fans will be needed to flush out the hot air inside and replace it with cooler outside air. These temperature controlled attic fans can be installed to lower the operating

temperature of the array, thus increasing its efficiency. This area requires further investigation.

During the summer months in Arizona, it's common for the outside air temperature to reach 105° or higher. The temperature inside of an attic can be much higher thereby causing the array to operate at a higher temperature. Research has shown solar-cell power output decreases with an increase in temperature. The silicon-cell voltage drops at an approximate rate of 2 mV for every 1° C increase. Using a standard equation for heat transfer shown below, the temperature inside of the attic can be found (Ref. 9).

$$Q = A \times C \times (T_1 - T_2),$$

where,

Q = rate of heat transfer (BTU/Hr),

A = area of the roof (sq. ft.),

C = thermal conductance (BTU/Hr-sq.ft.-°F),

T_1 = air temperature inside of the attic (°F),

T_2 = outside air temperature (°F).

Thus, according to Table A.2 in appendix A, the maximum insolation on a south-facing 20° tilted surface occurs during May with a value of 8.19 kWh/m^2-day or 216 BTU/Hr-sq.ft., which is the value Q/A. The area of the roof exposed to this insolation is 1,276 sq.ft. (see the next section). The conductance of asphalt shingles is 6.50 BTU/(Hr-sq.ft.-°F). If the worst case outside air temperature is T_2 = 110° F, then the inside

attic temperature reaches,

$$T_1 = Q/(A \times C) + T_2 = (216/6.5) + 110 = 33^\circ F + 110^\circ F$$

$$T_1 = 143^\circ F$$

From Figure 3-2, the Normal Cell Operating Temperature (NOCT) for the M-55 module is 47°C or 117° F. Thus, there is a 26° F (or 15° C) temperature difference between the NOCT and actual operating temperature. This results in an approximate voltage drop of,

$$\text{Silicon cell voltage drop} = (2\ mV/1^\circ C)(15^\circ\ C) = 30\ mV$$

With 36 cells per module, this results in a module voltage drop of 1.08 V. The power drop per module is then,

$$(3.05\ \text{amps})(17.4 - 1.08) = 49.8\ \text{watts},$$

a difference of 53 - 49.8 = 3.2 W/module. Multiplying this value by the total number of modules in the array (72) gives a loss of,

Total temperature power loss = (3.2 W/module)(72 modules) = 230 W

This is a conservative estimate. In actual use the loss is likely to be significantly higher. In order to avoid this loss, a small temperature controlled fan is installed in the attic to reduce this heat buildup, although it itself will consume about 200 W.

One advantage of this design is that this hot attic air can be

circulated through heat exchangers for house heating or across thermal storage devices for hot water heating as a form of passive solar heating.

Another advantage is that if any of the solar modules need to be repaired, the damaged module can easily be removed, as well as any other array components.

The main advantage of using the integral mount is because it has the lowest installation costs of the four most common installation designs described. The reason for this is the lower labor and material costs which result from having the array built as a part of the roof.

3.5.5 Roof Loading Characteristics

The array is roof integral mounted, lies at an angle of 20° above horizontal, and faces true south.

Area of each module = (50.9 in)(13 in) = $\underline{661.7\ in^2}$ or $\underline{4.595\ ft^2}$

Area of the array = (72 modules)(4.595 ft^2/module) = $\underline{331\ ft^2}$

The roof area of a typical house (4 BDRMS, 1600 sq. ft., Ranch style) is approximately = (58' long)(44' wide) = 2,552 ft^2.

One-half of the roof area (south face) is = 1/2(2,552) = $\underline{1,276\ ft^2}$.

Weight of the array = (72 modules)(12.6 lbs/module) = <u>907 lbs</u>

Roof loading limits (typical house) = <u>350 lbs/100 ft^2</u>.

Loading of the array = <u>907 lbs/345 ft^2</u> or <u>263 lbs/100 ft^2</u> which is well within the limits.

For comparison purposes, let's look at how many modules we can fit on the typical roof and then estimate its maximum output power. Again, consider only the south facing side of the roof where the total area is about 1276 ft^2.

If we utilize 1200 ft^2 of this amount for the array, we can install approximately 242 modules whose total output power is roughly (242 modules)(43.1 W/module) = <u>10.4 kW</u>, a rather impressive amount. Unfortunately, the economic analysis on this configuration shows the costs to be prohibitive, even though the array is generating more power.

SECTION 4.0
INTERFACE ISSUES

The solar PV array is a DC source with a variable output capacity dependent on transient operating conditions such as changing insolation levels. It has a well defined current-voltage (I-V) curve which can change instantaneously with array temperature and insolation. The array can operate anywhere at any point on its I-V curve. It acts much like any other DC source except that it cannot generate fault currents or voltages much greater than the peak-power current or voltage.

4.1 ROLE OF THE PCU

The array depends on the PCU for control and conversion of the DC power supplied. The PCU causes the array to operate at a fixed voltage that continually tracks the maximum power voltage and converts the available DC power to AC power. With utility inter-tie, the PCU supplies the AC power to the utility interconnection where it drives the onsite loads and feeds excess power back into the electric utility grid.

The SI-3000 is a microprocessor controlled power conditioning system which uses field effect transistors as switching elements. A ferrite isolation transformer isolates the DC array from the utility line. A sine wave current reference waveform is generated from a variable amplitude look up table in the processor memory. Power factor is forced

to unity by operating the PCU as a sine wave current source in phase with the utility voltage.

If any solar PV system has a utility inter-tie, it's extremely important the PCU function to isolate the system anytime the utility voltage is missing or out of tolerance. If the PCU fails to disconnect from the utility during a power outage, the solar PV system may continue to energize a section of line that would otherwise be unenergized due to the outage. This creates a serious, potentially lethal hazard for utility linemen and other persons who may work to repair the line.

Also, it's important for the PCU to be able to differentiate between utility voltage and the voltage supplied by another solar PV system connected to the same line. A solar PV system may continue to operate or "run-on" during an outage if it "sees" the voltage supplied by the other PV system as the actual utility voltage. This is known as "islanding" between the two systems that continue to operate and again creates an unacceptable safety hazard. The SI-3000 uses SCR thyristors in an unfolding circuit combined with tight monitoring of utility line voltage and frequency to prevent any possibility of running-on during a utility outage. The PCS modulator stage is a center-tapped, high frequency link, pulse width modulated inverter. This section generates a sinusoidal current in the form of a carrier modulated at a 60 Hz rate. The carrier frequency varies from approximately 50 to 100 KHz depending upon the instantaneous line voltage (Ref. 1). As soon as it detects the loss of the utility supplied voltage, the SI-3000 shuts down and isolates the array.

Unfortunately, the customer loses both utility and solar electric power.

If a short circuit occurs on the AC side of the SI-3000 PCU, the internal logic of the PCU will detect it through its logic array, interrupt the current, and shutdown automatically. If the AC fuse or circuit breaker doesn't blow or trip, respectively, then the PCU will continue to monitor the utility voltage and current.

When conditions return to normal, the PCU will turn on again and operate as usual.

4.2 SYSTEM CHARACTERISTICS

4.2.1 Startup Sequence of the SI-3000:

First, the external switches on both sides of the PCU should be closed in either order. The operational display of the PCU will remain blank until DC power is applied because inverter logic power is derived from the array power. The display will show accumulated kilowatt-hours during startup or restart.

Of the six display digits shown, the four leftmost digits indicate the magnitude of the data selected. The far right digit shows a value related to inverter status while the fifth digit shows a code corresponding to the reason for the last previous inverter shutdown.

As soon as the array voltage is above 15 Vdc and the AC disconnect is closed, the display will show kWh in the left four digits and status in the right digits. There are many different digit codes which have different

meanings. For example, an inverted U signifies the AC disconnect is open or both internal line fuses are blown. If proper utility and line voltage are present, the rightmost digit will display a 1. The inverter logic has now synchronized. After 4.26 seconds the status digit will change to P and the inverter will start if the monitored values are within limits. If a monitored value is outside of a limit, no start attempt will be made, and a status code will appear. During the next startup attempt the status code displayed will move to the fifth display digit and the present code will appear in the rightmost digit.

The most usual code displayed is a 6 for insufficient array voltage. Once all monitored conditions are within limits, the inverter starts at low power level. A zero in the status digit indicates operation in the maximum power tracking mode. Approximately one minute is needed to reach the peak power point.

4.2.2 Daytime Operation

If the output current exceeds 12 amps, the PCU acts to reduce it to prevent an overcurrent trip. If the array voltage drops to 42 Vdc, the control reduces load to prevent shutdown on under-voltage and the status digit displays an A. If the heat sink temperature exceeds 70°C, load current is reduced to 6 amps and the status digit displays a degree symbol. If the heat sink exceeds 72°C, the load current drops to 3 amps. At 75°C the inverter shuts down.

During dark periods such as nightfall or a passing cloud, the microprocessor remains in a low power (WAIT) mode with only its timer running. Periodic tests of the array voltage allows automatic startup. The low power required is supplied by a Ni-Cad battery.

4.2.3 Shutdown:

The microprocessor logic is such that if the dark period lasts long enough, the PCU will begin its shutdown mode. If the period is short, the PCU will wait for a short time and start up again. The inverter is fully automatic and will start and stop without attention.

4.3 HARMONICS

Harmonic distortion has been a significant problem with utility interactive solar PV systems in the past and deserves some mention here. If there is only one solar PV system connected to the utility distribution feeder, the amount of Total Harmonic Distortion (THD) it interjects into the line is insignificant to cause any problems. For example, the SI-3000 PCU has a harmonic current distortion of less than 5 % RMS. The total voltage harmonic distortion does not exceed 2 % RMS. The maximum single frequency voltage harmonic does not exceed 1 % RMS. The THD of the PV-system is low.

The harmonic current injection from advanced, self-commutated PCUs

such as the SI-3000 has been described in the literature as "in the noise" and less than injection levels from common household appliances such as air conditioners and color TV sets. However, published harmonic data appear to consider only a few lower-order harmonics. As compared to a background corresponding to utility-only excitation, it has been observed that a significant increase in the amplitude of higher-frequency harmonics occurs when PV-system excitation is added. In Ref. 5, at a test facility, it was found that these higher-frequency harmonics interfered with the utility's system of communication and control for distribution automation. When 1000 PV systems are connected to a utility subtransmission line at one point, the problem grows even worse as the magnitude of the harmonics injected into the line is significant. Filters will be required to reduce or eliminate both the lower-order and high frequency harmonics to prevent detrimental distortion of utility power and control systems.

The size and type of these filters could only be determined through an extensive test of an actual PV system involving the SI-3000 PCU and using a computer model to estimate what the harmonics would be for 1000 systems connected together at one point. This is beyond the scope of this paper at this point, but such a study is necessary before an actual solar village could be built.

4.4 DYNAMOTE UXB-6.0-48 POWER INVERTER OPERATION

The power inverter is located between the battery array and the AC panelboard for the house. The inverter draws its power directly from the storage batteries which are being charged throught the battery controller by the PV array. The inverter runs automatically when it is switched on. It protects itself against overload, high temperatures, and short circuits by shutting itself off. When battery power is low, the inverter shuts off to prevent damage to the inverter and the batteries. LEDs on the inverter are used for troubleshooting and locate the problem, whatever it may be. When the problem is corrected, the inverter starts up again automatically and continues operation.

SECTION 5.0
SYSTEM ECONOMIC EVALUATION

An important part of any conceptual design is how much money is it going to cost to design, build, operate, and maintain the system. Does it cost too much? Can the costs be reduced without sacrificing quality and reliability? How does it compare to other designs? In order to answer these questions, a standard procedure for estimating costs must be used for all of the designs to establish comparable estimates. Then the choice for the most economically feasible design can be made.

5.1 ECONOMICS

The economic feasibility of a PV system can be assessed by subtracting the present value of total costs from total financial benefits. This can be a complicated process, however, because of the various changing factors that must be evaluated over the system's lifetime. For example, the price of electricity, as well as the price of energy and goods, will vary over time. The financial market rates that are used for borrowing money and for investment opportunities can also vary significantly with time, especially when looking at a period of ten or twenty years. Thus, to be able to make the benefit-vs-cost comparison, some educated guesses as to how these important cost variables will change need to be made. Also, a common reference point

for all of these costs must be established.

Cost-effectiveness can be evaluated by using a technique called present worth analysis which normalizes all financial transactions to the present. There are other economic techniques which can be used but will not be discussed here. In present worth analysis, all of the costs and benefits of the system which are affected by money's changing value over time are adjusted to the present by multiplying them by a uniform present worth factor that accounts for life-cycle price escalation and loan or investment discount rates.

If the present worth value is positive, which indicates that the benefits are greater than the costs, than the system is economically viable. If this value is negative, than the costs outweigh the benefits and certain design changes, if possible, must be made to reduce the costs. Keep in mind that this analysis is only as accurate as the financial predictions made as well as the design itself.

But money isn't the only measure of deciding whether a solar PV system is practical and desirable. Solar energy is clean, quiet and is relatively simple to understand, construct, and maintain. Users also have the advantage of being energy independent, to a degree. While these factors are subjective considerations, they may be important enough to build the system in spite of a negative net present worth value.

5.1.1 System Costs

The first part of the present worth analysis involves assessing and estimating all of the costs associated with building the solar PV system. Most of the cost for the system will be initial costs (materials, design, installation, etc.) since very little money is needed to operate and maintain the system. If these costs are to be deferred, then money must be loaned, at a price, to pay for the system. Thus, all of the expenses must first be added up to see what the solar PV system will cost.

One method of determining the price of a PV array is to first find the array area (A), packing factor (PF), and system efficiency (PVE) and then use the equation below to find the PV array's peak power (PP).

$$PP = 1000 \times A \times PF \times PVE/100$$

The PV array's price then simply equals the total peak power multiplied by the existing price per peak watt. See Table 5-1.

Because the array will be integrally mounted into the new roof, a savings will be realized from reduced materials and labor. The cost of the power-conditioning unit and other equipment needed for the array can be found once the array size and location has been determined. For this design, the power-conditioning and additional solar equipment will be located in a separate room attached to the outside of the house, an

additional expense. Of course, fees for the design and installation of the system must also be taken into account.

Other costs will include small operating and maintenance costs to keep the system working properly. This would include washing the array periodically and making small repairs. Insurance for the array is recommended, although this means increased premiums. Also, it's reasonable to expect property taxes on the house to increase slightly. All of these values are estimated in the cost analysis.

Because operating & maintenance expenses, insurance premiums, and taxes accumulate over the system's lifetime, they too, will be affected by the changing rate of money. For the designs considered here, the inflation rate, discount rate, and the system's lifetime will be estimated and varied for comparison. These expenses are normalized to the present by using the uniform present worth factor which can be found in various economic books.

Although most tax incentives for alternative energy sources have been diminished recently, some statewide tax savings can still be realized through various forms. These tax savings were greater in the early 80s, but because the interest in solar energy has lessen recently due to more plentiful oil supplies, federal and local governments reduced their tax saving incentives. Arizona continues to offer some incentives, but they are mainly for the small PV user. In any case, the savings are small and are not considered significant in the final cost analysis.

Once the system's total initial cost is found, the developer must

determine if capital is needed to help pay these costs. If a loan is taken out, the interest charged on the principal of the loan will increase the system's final cost over the specified time period. Again, the interest rate used will depend on the economy at the time the loan is secured. A lower interest rate results in a lower cost and vice versa. Finally, at the end of the system's useful lifetime, much of the hardware will have a salvage value. Some of the structural and electrical components can be recycled. A common estimate for the salvage value is about 5% to 15% of the present price of the entire system (Ref. 6).

5.1.2 System Benefits

While solar energy systems have varied benefits, the most important one in most cases is the financial benefit derived from the value of the electricity generated. This value can be found by estimating how much money would be earned over the system's lifetime if the electricity generated were to be sold.

The first step of this estimating process is to determine how much electricity will the PV array generate. How much of this electricity can be used and how much will be wasted? In most cases, a utilization factor will need to be calculated to indicate how much electricity can be expended for useful purposes. In a stand alone system, the battery array may be unable to store all of the energy supplied by the solar PV array, although this is unlikely for the houses in the solar village because of

their high energy demand. But if it happens, the excess energy will have to be diverted or discarded. In a utility-interactive system, the utility may buy the elctricity back at a lower price than what they sold it for, i.e. the buyback ratio will be less than one.

Thus, the *utilization fraction* is an indication of how much solar electricity is discarded or undervalued. This value can be difficult to measure because of changing prices, weather patterns, etc.

One way of determining the utilization fraction is to use power versus time of year or energy versus time of year plots. The excess amount of energy during a typical day over the year can be determined from these plots.

Also, as mentioned before, the price of electricity needs to be known now and estimated for the future. What future events may drastically change the price? How will the system's benefits compare to other investment opportunities? While there is no reliable method of predicting these factors, one way is to check on the past. How much has the price of electricity increased over the last 5 years? What has the economy done? However, in looking at the past, one must be wary of assuming economic conditions will continue unchanged. Speaking from the bottom line, many assumptions have to be made with the realization that a small change in the inflation or discount rates can have a significant impact on the outcome of the present worth analysis.

5.1.3 Net Present Value

Once the present value of system costs and system benefits have been calculated, the net present value can be calculated by subtracting the system costs from the system benefits. A positive net present worth indicates the system will at least pay for itself within the system's lifetime, assuming all of the criteria is correct. On the other hand, a negative net present value says the system is not economically worthwhile. In this case, the system factors used in the analysis need to be perused to see if changes can be made to improve the result. Some factors may be beyond the control of the designer. Are tax incentives to low? Interest rates too high? Price of electricity too low?

These thoughts were kept in mind during the economic evaluation of the designs which follow in this report. Current factors were taken from sources as recent as possible with future values being estimated with an eye on the past. Specific assumptions will be discussed during the evaluation.

5.2 RESIDENTIAL DESIGN COST EFFECTIVENESS PROCEDURE

The following economic evaluation procedure is taken from Ref. 6. The procedure is used to evaluate the cost-effectiveness of the photoelectric residential system designs based on the preceding discussion. This procedure was inputted on a computer spreadsheet program where

different economic values were used for comparison.

The cost data for three different residential solar PV designs, discussed later in this report, are entered into this spreadsheet program and evaluated to see if they are economically feasible to build. The values selected for the variables are listed in the printouts of each of the runs which can be found in Appendix A. The results for each run are used in the final economic analysis for the three different solar PV designs discussed in the next section.

5.2.1 Photovoltaic System Criteria

1. PV-array size A, m^2 __________

2. PV-array packing factor __________
   (a fraction between 1 and 0)

3. PV module efficiency PVE at NOCT, % __________

4. Power conditioning efficiency PCE, % __________

5. PV-array peak power PP at NOCT, W
   PP = 1000 X A X PF X PVE/100

   ____

6. PV-system expected useful lifetime L, yr. __________

6.2.2 Photovoltaic System Costs

1. Peak-watt PV module costs MC, $/W __________

2. PV-array costs PVC, $

   PVC = MC X PP = __________

3. PV-array support structure costs SC, $ __________

4. PV-system power conditioning costs PC, $ __________

5. PV wiring materials costs WC, $ __________

6. Design and installation labor costs LC, $ __________

7. Annual property tax increase PT resulting from addition of PV system, $ __________

8. Annual insurance premium for PV system IC, $__________

9. Annual PV system maintenance costs MC, $ __________

10. Predicted average annual general price escalation rate over lifetime of PV system ER1, $ __________

11. Predicted average annual discount rate for borrowing money over lifetime of PV system DRI, % __________

12. Uniform present worth of costs UPW1 based on L, ER1, and DRI __________

13. Percentage of PV system costs deducted for tax or depreciation credit TC, % __________

14. Salvage value SV after system lifetime, $ __________

15. Total PV-system costs TPC, $

    TPC = {[PP X PVC) + SC + PC + WC + LC + UPW1 X (PT + IC + MC)] - SV} X (100 - TC)/100__________

16. Loan down payment DP, $ __________

17. Term of loan TL, yr __________

18. Loan discount rate DR2, % __________

19. Predicted average annual general price escalation rate over term of loan ER2, % __________

20. Loan uniform present worth UPW2 based on TL, ER2, and DR2 __________

21. Loan monthly payments MP throughout duration of term, $

$$MP = \frac{(TPC - DP) \times [(DR2(1 + DR2)^{TL}]}{12 \times [(1 + DR2)^{TL} - 1]} = \_\_\_\_\_\_\_\_\_\_$$

22. Present value of PV-system costs NSC, $

$$NSC = DP + (TPC - DP) \times (TL/UPW2) = \_\_\_\_\_\_\_\_\_\_$$

6.2.3 Photovoltaic System Benefits

1. Annual average daily solar energy SE, kWh/m2·day __________

2. Utilization factor UF __________

3. Present available elctricity costs EC, $/kWh ____________

4. Predicted average annual escalation rate of electricity prices over lifetime of PV system ER3, % ____________

5. Discount rate for alternative investment opportunities DR3, % ____________

6. Benefit uniform present worth UPW3 based on L,. ER3, and DR3 ____________

7. Annual PV-system useful output PVO, kWh/yr
   PVO = 365 X SE X A X PF X PVE/100 X PCE/100 X U = ____________

8. Present value of PV-system output over lifetime VPO,$
   VPO = PVO X EC X UPW3 = ____________

6.2.4 Net Present Value

1. System benefit minus costs NPV, $
   NPV = VPO - NSC = ____________

Many variables are included in this cost analysis which directly effect the final result: The Net Present Value. It's important to realize that a small change in some of these variables, such as the interest rates, can have a significant effect on the final outcome. The values selected for cost analysis later in this report have been based on past indicators and future projections as discussed earlier and are considered to be as accurate as possible for the economic comparisons made later in this report. The uniform present worth factors can be found in most economic books on the subject.

5.3 BUILDING COSTS

To help establish an idea on the total cost of a residential solar PV system, the building costs for a typical house and apartment building have been calculated. The costs found here do not include the cost of the PV system. Basically, the most costly aspect of constructing any building or structure centers on ten main components. They are: Site work, Foundations, Framing, Exterior walls, Roofing, Interiors, Specialties, Mechanical, Electrical, and Overhead and Profit.

Of course, many adjustments to these main components can be made, but this report will only look at generalized costs. The figures given here are taken from Ref. 10.

5.3.1 Residential

Residential buildings are divided into four types: Economy, Average, Custom, and Luxury. For purposes of evaluation and standardization, only the costs for the average house will be used. The average house has these general design features.

- One story
- 1600 ft^2
- Simple design from standard plans
- Single family - 1 full bath, 1 kitchen
- No basement
- Asphalt shingles on roof (except for where the solar array lies)
- Hot air heat
- Drywall interior
- Attached two car garage
- Materials and workmanship are average

The base cost per square foot of living area for a one-story house with 1600 ft^2 of living space is: $74.60 This assumes wood siding with a wood frame. Thus, the subtotal cost is (1600)(74.6) = $119,360.

5.3.1.1 Adjustments

Two car garage - attached, wood, includes one door, manual overhead doors and electrical fixture. Cost: $7,900

Appliances - refrigerator, range, dishwasher, garbage disposal, electric water heater, etc. Cost: $3,360

Kitchen cabinets - Various sizes. Cost: $1,300

Subtotal cost of adjustments: $12,560
Total cost of the residential house: $131,920
Multiply by a factor of 1.2 to account for transportation costs.
The total, w/o the solar PV system, is then: $158,304

5.3.2 Apartment Complex

These costs are calculated for a 3-story building with 10-foot story height and 22,500 square feet of floor area. The exterior walls have a wood siding with a wood frame. There is no basement. The cost per sq. ft. is $45.10, which doesn't include the adjustments listed below. Thus, the subtotal cost is (22,500)(45.1) = $1,014,750

5.3.2.1 Adjustments

Appliances - Cost: $28,920 for entire building.

The total for the building is $1,043,670

Multiplying by 1.2 gives $1,252,404 w/o solar PV system

These figures, while a bit high, give a good estimate of what a new house and apartment building would cost if built today in a semi-remote area of the Arizona desert. Adding to this the cost of the residential PV system, which for the stand-alone system is approximately $70,000, gives a total of ≈ $230,000 (see appendix A). This cost for a new home is beyond the reach of most families and would be accessible primarily to the affluent.

Thus, a technical description of the residential solar PV energy system and the associated cost has been presented to be used in the analysis for the three different solar PV energy system designs for the solar village.

The next section describes the designs for the intermediate and large commercial/business buildings along with their associated costs. These designs build off the groundwork laid for the residential systems and use many of the same components. Following this section is the analysis of the three designs for the solar village: Stand-alone, Stand-alone with Interconnection, and Central Solar Plant. These designs are then compared to the design of supplying the solar village with utility supplied electricity.

5.4 INTERMEDIATE AND LARGE SYSTEM DESIGN

In the preceeding sections, a detailed design for a solar PV electrical system for a residential house for use in the solar village has been presented. Now it's time to take a more general look at what will be required to provide solar power for an office complex or large store and an apartment building. For purposes of comparison needed later on in the report, a system for an apartment building and another system for a large grocery store will be presented. These designs are general in nature because the main areas of concern here are their practicability and their approximate cost. A detailed design is not needed to make the comparisons. These systems will be designed to operate independently with backup power initially being provided by storage batteries and later by a diesel generator.

5.4.1 Apartment Building

Using an example as presented in Ref. 7, the apartment building is equipped with electric cooking, space heating and air conditioning, and has 40 units. The meters are in two banks of 20 each which also house the metering and individual subfeeders to each dwelling unit. Each dwelling unit is equipped with an electric range of 8 kW nameplate rating, four 1.5 kW separately controlled 240 volt space heaters, and a 2.5 kW 240 volt electric water heater.

Assume range, space heater (or air conditioner), and water heater kW ratings equivalent to kVA.

The computed load for each dwelling unit follows under NEC Art. 220

General Lighting Load (840 ft^2 at 3 VA/ft^2)..........2520 VA

Small Appliance Load, two 20 Amp circuits..........3000 VA

Total computed load without range and AC..........5520 VA

Application of Demand Factor

3000 VA at 100%..........3000 VA

2520 VA at 35%..........882 VA

Net computed load without range and AC..........3882 VA

Range Load at 80%..........6400 VA

Space AC..........6000 VA

Water Heater..........2500 VA

Net computed load for individual dwelling unit..........18,782 VA

Total computed load for the entire apartment building:

Lighting and Small Appliance Load (40 x 5520)..........220,800 VA

Water and Air Conditioning (40 x 8500)..........340,000 VA

Range Load (40 x 8000)..........160,000 VA

Net computed load for the building..........880,800 VA

From Table 220-32, the demand factor for 40 units is 28%.

Thus,

880,800 VA x 0.28 ....246,624 VA

Therefore, the maximum demand = 246.624 kW.

5.4.1.1 Solar PV Equipment Requirements (Major Components)

Modules: To supply a peak demand of this magnitude would require an array containing the following number of solar modules:

Number of modules = 246.624 kW/43.1 W per module = 5,722 modules

More modules may be necessary to provide charging power to storage batteries (if used) during times of peak demand. For purposes of comparison, however, this isn't a significant factor.

Inverters: Four 70 kVA self-commutated inverters are necessary to handle the peak power output.

Batteries: Assuming the system is operating at 240 Vac, 24 two volt batteries need to be connected in series for a 48 VDC input. Earlier it was found that 64,000 AH are needed for a single house for a stand-alone system to provide a two day supply of energy. For purposes of comparisons, let the 64,000 AHs provide short term backup power. This

is a conservative estimate, but it will point out the high expense of the stand-alone system. Maintenance is a problem as well as the the increased probability of a short circuit, bad battery, etc. which can affect the reliability of the system. Also, if it is necessary to provide power for more than two days, the array size must be increased which adds to the cost and the problems.

Diesel Generator: As an option to batteries for backup power is the use of a 250 kW diesel generator. A generator is easier to care for and can provide power for a much longer time. However, a generator is noisy and expensive to operate. To use it every night would be noisy and unacceptable to the residents of the village,and would net an expensive fuel bill. A compromise could be made where the batteries could supply enough power to last for short periods, such as temporary cloudiness, and the generator could be used during extended periods of cloudiness or in an emergency.

The approximate cost of this system is shown below.

5.4.1.2 System Cost

Modules: (5,722 modules)($343/module) = $2,134,300

Inverters: (4 inverters)($16,500/inverter) = $66,000

Batteries: (44 batteries)($340/battery) = $14,960

Diesel generator: Cost of a 250 kW diesel generator (standby with transfer switch) including heater, batteries, and all other necessary equipment is approximately $23,000.

Total approximate cost of major components = $2,238,260.

In addition to this cost is the cost of a computer controlling system, maintenance and repairs, and other miscellaneous items.

5.4.2 Large Grocery Store

The engineers in the Load Analysis Section at APS stated that a large grocery or department type store with some adjacent small shops would pull an annual peak demand of approximately 500 kW. This value is used in the following analysis.

5.4.2.1 Solar PV Equipment Requirements (Major Components)

Modules: Assuming a peak demand of 500 kW, a minimum number of solar modules required is

(500 kW)(43.1 W per module) = 11,600 modules

Again, this is the minimum number needed. Recharging the batteries will require more modules during times of peak demand.

Inverters: Two 250 kVA self-commutated inverters are require for this size of load.

Batteries: As with the apartment building, let the 64,000 AHs of battery power provide short term backup power and rely on the diesel generator for long term power.

Diesel Generator: As before, a backup diesel generator may be a better solution than having an enormous storage battery array. However, it faces the same problems as mentioned before: noise, expensive fuel, and mechanical breakdown.

The approximate cost of the major components for this system are given below.

5.4.2.2 System Cost

Modules: (11,600 modules)($343 per module) = $3,979,000

Inverters: (2 inverters)($25,000/inverter) = $50,000

Batteries: (44 batteries)($340 each) = $14,960

Diesel Generator: A 500 kW diesel generator costs approximately $50,000, complete with transfer switch and other items as described for the 250 kW generator.

Total approximate cost of the major components = $4,093,000

5.5 ANALYSIS OF DESIGNS

The analysis of the operation, cost, and practicability of the solar village follows using three different design methods: stand-alone without interconnection, stand-alone with interconnection, and utility supplied electricity. The three designs will then be compared to see which one is the most economically feasible and why.

5.5.1 Stand-Alone w/o Interconnection

5.5.1.1 Operation

In this design, each system must have its own solar PV energy system which must be able to meet the electrical energy needs for the house/business for a 20 year period. Each system operates independently and has no effect on neighboring systems. Because the coincidence factor is one, the solar array must be large enough to cover the peak

demand of the user and have additional energy left to charge batteries, if necessary. Backup power must be provided by a storage battery array or a small electric generator or both.

5.5.1.2 Practicability

From a practical point of view, this design has three advantages worth mentioning, at least for the residential part of the village. First, with each system being independent, there's no need for a distribution system to interconnect the systems, which lowers the cost significantly.

Second, if a fault or damage occurs in one system, it won't affect the operation of the other systems, hence increasing the reliability. Also, each homeowner has pride in ownership of his/her system.

Unfortunately, one major disadvantage makes this design economically unfeasible as will be shown later. The main reason is because each of the stand-alone system arrays must be larger than if the systems were interconnected. This is due to what is called the *Coincident Factor*. The coincidence factor Fc is defined in Ref. 11 as "the ratio of the maximum coincident total demand of a group of consumers to the sum of the maximum power demands of individual consumers comprising the group both taken at the same point of supply for the same time." That is,

$$Fc = \frac{\text{coincident maximum demand}}{\text{sum of individual maximum demands}}$$

Thus, for a stand-alone system, Fc = 1.0 because only one system is used.

For an interconnected residential area consisting of 900 customers during peak loads,

Fc = 0.57 Summer

Fc = 0.29 Winter

These figures are supplied by the Salt River Project.

Thus, if each of the 900 homes has its own system without being interconnected, each solar array would have to meet a peak demand of 10.8 kW, which is a typical peak demand for a residential house of 1600 sq. ft. in Phoenix for the month of August.

Now, if all of those houses were connected together, this value drops to

$$\text{Peak demand per house} = (10.8\ \text{kW})(0.57) = 6.16\ \text{kW}$$

which is a difference of 4.64 kW.

This results in a reduction of (4.64 kW)/(43.1 W/panel) = 108 solar panels per house.

Thus, the stand-alone system requires larger, more costly solar arrays.

For commercial applications, this difference is even larger.

If an electric generator is used for backup power, a constant supply of

fuel will be needed. Also, there are the problems of noise and exhaust fumes being generated. Both of these problems are undesirable, especially in a solar village.

5.5.1.3 Cost Analysis

To make an accurate economic cost comparison between the alternative designs for the solar village, the same electrical loads, as determined from the load survey, are used for each design. All other factors, such as the weather, remain the same for each design also. The same system components, when applicable, are used and their costs are held constant. The solar PV system costs for a typical residential house, a medium-sized store, and a large store or office are calculated and added together to come up with a total solar PV system cost for a particular design. Then a final comparison is made to select the best economic design for the solar village.

Stand-alone residential house

From the load survey it was determined that the peak electrical demand for a typical house in August was 10.8 kW. The solar PV system developed up to this point is a 3 kW system. Thus, it's easy to see a much larger solar PV system is needed if all of the electrical demands of the house are to be met as well as providing enough excess power to

recharge batteries for backup power. Unfortunately, a system this large is extremely expensive as shown below.

In a solar village, most homeowners would be energy conscious and would work to try to reduce their peak demand on their PV system. Thus, it's reasonable to expect an annual peak demand of somewhat less than 10.8 kW, especially when the total connected load is 12 kW. However, for purposes of comparison, a 10.8 kWp annual demand will be used.

Therefore, the first cost analysis, using the computer spreadsheet program, is for a stand-alone solar PV system sized large enough to meet the 10.8 kWp demand.

Number of solar modules required = 10.8 kW/43.1 W per module

= 250 modules

This number of modules would just barely fit on the roof of the house as the array would cover 106.7 m^2.

Two of the Dynamote 6 kW power inverters are required in "stacked" operation. Also, to supply the necessary 64,000 AH, then 44 storage batteries are required.

Number of batteries required = 64,000 AH/1476 AH per battery

= 44 batteries

The equipment list, Table A.3 in appendix A, shows what is required and the corresponding initial costs. These figures were then entered into the

economic analysis spreadsheet program as described earlier to determine the present worth value of the system costs and benefits, and the net present worth value. The results for the house are given below.

Present Value of the Costs (PVC) = \$118,133

Present Value of the Benefits (PVB) = \$67,995

The net present value (NPV) is the difference between these two and is

NPV = \$67,995 -\$118,133 = -\$50,138

The present value of costs for stand-alone solar PV systems for 900 homes is,

PVC (900 homes) = \$106,319,000

From section 5.4.1.2, the approximate initial cost of a stand-alone solar PV system for a mid-size business or apartment building is \$2,238,260. For 45 of these systems, the cost is \$100,721,000.

From section 5.4.2.2, the approximate initial cost of a stand-alone solar PV system for a large office or store is \$4,093,000. For 5 of these systems, the cost is \$20,500,000.

The combined system cost is then <u>\$227,505,000.</u>

5.5.2 <u>Stand-Alone with Interconnection</u>

5.5.2.1 Operation

Basically, this method involves interconnecting together, through a common distribution system, all of the solar PV systems of each house and business to take advantage of the coincident factor, described above, which results in a lower power demand at any given time of the day. For example, the possibility of all of the interconnected houses having their air-conditioning (AC) units running at the same time is small. Thus, the power being generated by a house with its AC off can be used to provide power to a house with its AC on and vice-versa. Thus, each system operates on its own and shares its excess power with other customers.

5.5.2.2 Practicability

As shown in the preceding section, the major advantage of this design is the money saved building smaller solar arrays. Also, if one residential system malfunctions, the house may still be able to receive some power from the electricity in the distribution system. In the stand-alone system design, the house would be without power until repairs to the system were made.

Each system would still require small short-term backup power (batteries), but with a distribution system available, large diesel generators could provide power from central locations through the distribution system to the customers. This would be almost a necessity for the large commercial and business customers. Again, there are the

problems of noise and exhaust which would reduce the environmental quality of the village.

Of course, this design requires a distribution system be built at considerable expense. If such a system is built, then perhaps it would be best to supply utility generated electricity as described in the next section.

5.5.2.3 Cost Analysis

From section 5.5.3.2, the equipment cost of a distribution system is calculated to be \$9,545,000. If the subtransmission line is eliminated and the substation sized reduced, this cost becomes approximately \$7,545,000. Added to this cost is the cost of the solar PV systems for the houses and businesses.

Residential House

Because of the interconnection between the houses, the peak demand of the house drops to 6.41 kW. This requires

6.41 kW/43.1 kW per module = 149 modules.

This covers an area of 64 m^2. The battery requirement remains the same: 64,000 AH provided by 44 batteries. Table A.4 in appendix A lists

the equipment needed and the corresponding costs. The costs were again entered into the spreadsheet program with the following results.

Present value of costs = $66,922

Present value of benefits = $40,034

The net present value of this design is NPV = -$26,887.

For 900 homes, the present value of costs is

$$NPV = (900)(\$66,922) = \$60,300,000$$

Now the present value of the costs for the mid-sized and large commercial customers will remain approximately the same as was determined in section 5.5.1.3. This is because these customers consume large amounts of energy on a continuous basis and because they are so few in number. Thus, the results are repeated here.

From section 5.4.1.2, the approximate initial cost of a stand-alone solar PV system for a mid-size business or apartment building is $2,238,260. For 45 of these systems, the cost is $100,721,000.

From section 5.4.2.2, the approximate initial cost of a stand-alone solar PV system for a large office or store is $4,093,000. For 5 of these systems, the cost is $20,500,000.

The combined system cost is then = $181,521,000

As before, this is a truly prohibitive cost.

5.5.3 The Solar Village with Utility Supplied Electricity

The preceeding sections of this report have shown that a solar village completely dependent on the sun for its electrical energy needs is, at this time, economically prohibited and technologically complex. It's now time to examine the option of providing the village with utility supplied electricity and to see how this compares to the earlier designs. Again, major factors such as practicability, cost, and maintenance will be studied and discussed.

As mentioned before, the site of the solar village is considered to be approximately 30 to 50 miles away from the Phoenix area and preferably located on state land. The distance is such as to separate the village from the Phoenix metro area and existing electrical secondary distribution network but close enough so that the meterological data for the Phoenix area can still be used. Also, locating the village on state land would, with the state's backing, eliminate the cost of buying land from private interests.

Within these guidelines, the village should be located as near as possible to existing subtransmission lines to reduce the cost of building

a new line to the village. While many possibilities are available for consideration, the most promising areas appear to be either west of Phoenix along Interstate 10 or to the southeast near Coolidge, Arizona. These two areas have several existing subtransmission lines (69 kV) passing through them, either from APS or SRP. For the purpose of the design, assume the village is to be located within 10 miles of an existing 69 kV subtransmission line which has enough capacity to handle an additional 10 MW load.

The distribution design presented here is based upon existing networks in the APS service area. In this way, costs and construction estimates can be made much more easily rather than creating a new design from scratch. Appropriate voltage drop calculations are shown to ensure correct sizing of wires.

Much of the following information for the design has been supplied by distribution engineers working for the Arizona Public Service Company.

Figure 5-1 shows a simplified diagram of a common radial distribution system which could be one of many different designs suitable for the village. The radial system was chosen because it provides the lowest cost of a new distribution system even though it also has the lowest reliability. This cost will be used for comparison purposes with the other design options for the solar village.

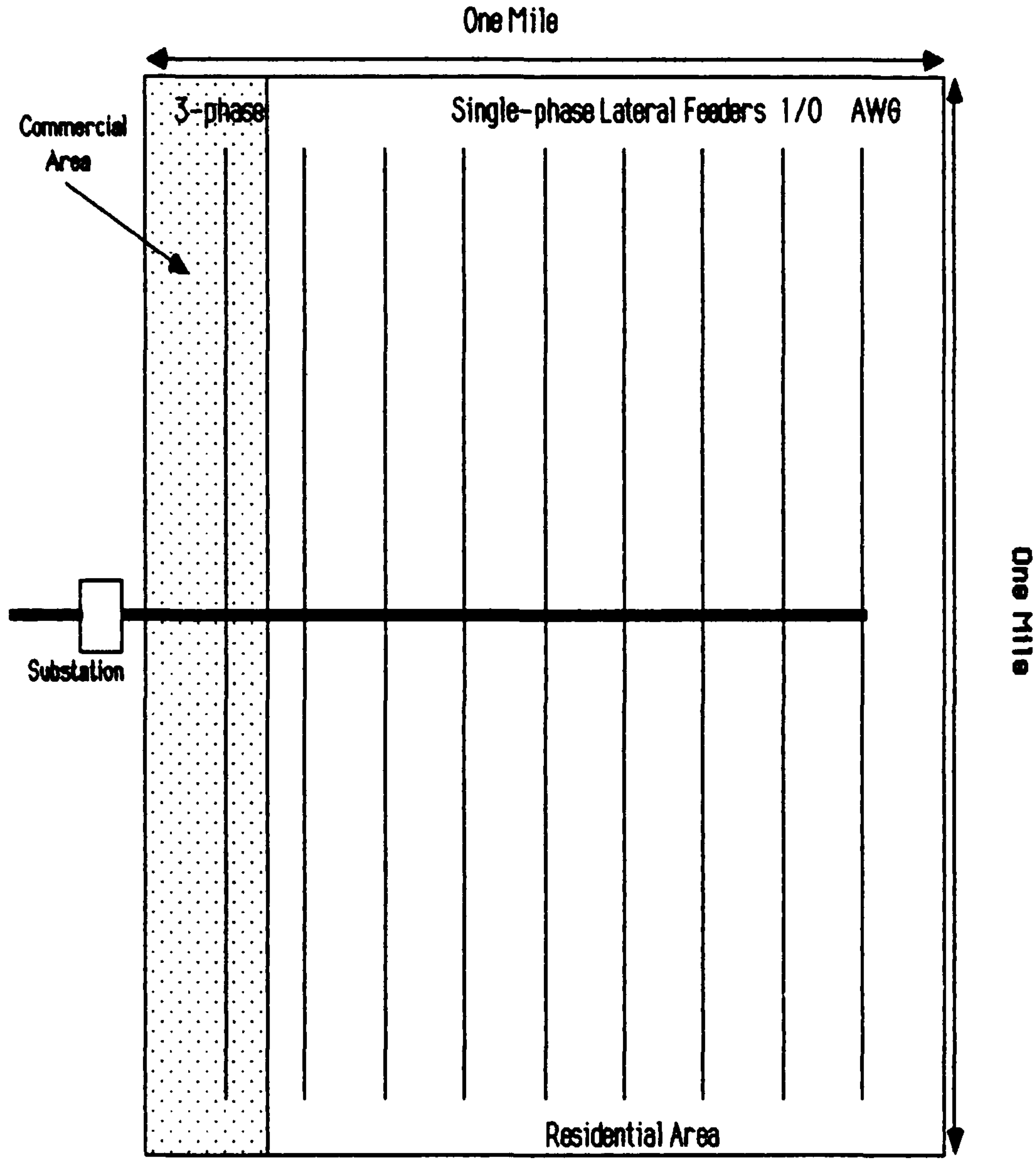


Figure 5-1. Basic configuration of the radial distribution system.

A new 69 kV subtransmission line, tied into an existing line at a distance of 10 miles, feeds a new distribution substation located at one side of the village.

While it would be more energy efficient to place the substation at the center of the village, the appearance of the overhead lines and the station would be objectionable to the residents living there. To keep voltage drop losses low, the large energy users of the village should be located as close as possible to the substation.

Although an underground system can cost between 1.25 to 10 times as much as an overhead system, the advantages it offers makes it worthwhile to pursue, especially for the solar village. Some of these advantages include greater reliability due to the lack of outages caused by severe weather, accidents, tree trimming, etc.; less maintenance; the aesthetic improvement of not seeing overhead lines; and increased safety from having the lines underground.

A single three-phase 69/12.47 kV transformer at the station is fused for 69 kV and is rated at 20 MVA. This value may seem high, but this is a standard rating for transformers at this voltage level and does not significantly add to the cost. It also allows for additional growth of the village. The secondary side of the transformer has three 12.47 kV circuit breakers.

A single primary feeder extends underground from the substation and travels directly across the center of the 1 sq. mile area as shown. This feeder is rated for 10 MW and consists of three 750 AA cables laid in a

trench. Eighteen lateral feeders, which supply the distribution transformers, extend underground from the primary feeder at roughly equal intervals with nine laterals on each side. The lateral feeders consist of 1/0 AA cables. Sixteen of the laterals are single phase with two 1/0 AA cables and feed the distribution transformers for the residential area.

Because current Arizona zoning regulations require new residential areas to have curved streets, these laterals will not be straight line. The remaining two laterals are 3-phase, 4-wire, have a capacity of 4 MW and are intended to supply the commercial and large energy use customers.

Although not shown in Figure 5-1, the primary radial configuration is equipped with the appropriate reclosers, sectionalizers, fuse cutouts, capacitor banks, etc. The costs for all of these components have been included in the cost per mile costs for installing the distribution cables. Only the transformers, because of their significant number and cost, have been analyzed separately.

The distribution transformers (wye-wye) in the residential areas each supply power to four houses and are rated 7.2 kV/240 V at 50 kVA. They are pad mounted and located in inconspicuous areas. Service feeds to the individual houses consists of 1/0 AA cables and provide 120/240 Vac to the house distribution panel with a 150 Amp main circuit breaker.

The commercial distribution transformers (wye-wye) are rated 12.47 kV/480 V at 250 kVA and 500 kVA depending on the need. A 250 kVA

transformer would be adequate for a store such as a Circle K while a Safeway or K-Mart would require a 500 kVA transformer.

The next step is to determine how much equipment (miles of cable, transformers, etc.) is needed for the village.

5.5.3.1 Equipment Needed

For purposes of comparison, the subtransmission line is assumed to be an overhead line roughly 10 miles long, terminating at the new distribution station. The line has a voltage of 69 kV and a power capacity of 100 MW. Equipment for the distribution station has already been mentioned. Approximately 3 miles of 750 AA underground cable for the primary is needed along with 50 miles of 1/0 AA underground cable for the laterals and service drops.

750 AA

(length of primary = 1 mi)(3 cables/primary) = 3 mi. of cable

Approximately one mile of trenching is needed for the primary. The cost of the cable, trenching, and associated equipment will be given together as one sum/mile.

1/0 AA

(8 laterals)(2 cables/1 phase lateral)(1 mile/lateral) = 16 mi. of cable

(2 laterals)(3 cables/3-phase lateral)(1 mile/lateral) = 6 mi. of cable
Assume 70 ft. for the length of the service drops with approximately 1000 service drops needed (900 for homes and 100 for schools, shops, offices, etc.).
(70'/drop)(mi/5280')(1000 drops)(2 cables/drop) = 26.5 mi. of cable
Total amount of 1/0 cable needed = 16 + 6 + 26.5 = 48.5 ≈ 50 miles

Approximately nine miles of trenching is needed for the laterals and an additional 13 miles needed for the service drops.

Transformers

Each 50 kVA distribution transformer will supply four homes. Thus,

(900 homes/4 homes/transformer) = 225 transformers

Ten additional transformers are required for some shops, small offices, and the like. Thus, the total comes to 235 (50 kVA) transformers.

If the village has one large grocery store, one large department store, and one school complex, then three 500 kVA transformers are needed. Some other shops can use these transformers as well.
For medium size stores such as a Circle K, a 250 kVA transformer is needed. Assume four such transformers are required.

5.5.3.2 Cost Analysis

The cost given below for the transformers include all associated equipment needed to connect the transformer to the system (protection devices, switches, etc.). The cost of other equipment such as reclosers, sectionalizers, and capacitor banks is included in the per mile rate for the line. The following costs includes meter, cable, trenching, etc., costs.

TABLE 5-1. UTILITY EQUIPMENT NEEDED AND COSTS

Equipment	Cost
Line:	
69 kV subtransmission line with 100 MW capacity	$150,000/mile
Substation: 69/12.47 kV rated 20 MVA	$700,000
Fused at 69 kV and with three 12.47 kV breakers	
Underground Cable (12 kV):	
1/0 AA cable rated at 4 MW	$400,000/mile
750 AA cable rated at 10 MW	$525,000/mile
Transformers:	
50 kVA 12.47 kV/480 V Single-phase	$2,000 apiece
250 kVA 12.47 kV/480 V Three-phase	$5,000 apiece
500 kVA 12.47 kV/480 V Three-phase	$10,000 apiece

Service Drops:

Service drop to residential home or small shop	$1,000
Service drop to mid-size and large customer	$2,000

TABLE 5-2. TOTAL COST OF THE UTILITY DISTRIBUTION OPTION

Equipment	Total Cost
Line:	
10 miles of 69 kV line at $150,000/mile	$1,500,000
Substation:	
One 69/12.47 kV Substation at $700,000	$700,000
Cable:	
13 miles of 1/0 AA cable installed UG at $400,000 per mile	$5,200,000
One mile of 750 AA cable installed UG at $525,000 per mile	$525,000

Transformers:

235 (50 kVA) Transformers at $2,000 each	$470,000
Four 250 kVA Transformers at $5,000 each	$20,000
Three 500 kVA Transformers at $10,000 each	$30,000

Service Drops:

900 residential service drops at $1,000 each	$900,000
100 non-residential service drops at $2,000 each	$200,000

Total Cost of Distribution System: $9,545,000

5.5.3.3 Voltage Drop Calculations

The calculations below determine the percent voltage drop of the distribution system from the substation to the farthest remote point of the radial layout (see Figure 6-1). The voltage drop will be found for three segments of the line and then added together to find the total. The first segment is the lateral which extends from point A to point B. The

second segment is the primary feeder from B to C, and the third segment is the rest of the primary feeder from C to D which includes the 3-phase loads. The lateral consists of 1/0 cable and the primary consists of 750 M cable rated at 75°. Assume a uniform power factor of 100%.

$$\Sigma\%VD_{tot} = \%VD_{AB} + \%VD_{BC} + \%VD_{CD}$$

The load on the lateral in uniformly decreasing. Thus, the load can be represented by a single load halfway down the line. There are 57 homes on each single-phase lateral where the maximum load demand (taking into account the coincident factor) is approximately (3 kWp/home)(57 homes) = 171 kWp. The 3-phase line voltage is 12.4 kV and the line-to-ground or single-phase voltage is 7.2 kV. The phase current is

$$I_{phase} = 171 \text{ kWp}/(\sqrt{3} * 12.4) \approx 8 \text{ A}$$

Now, the $\%VD_{AB}$ = (length/2)(K)(Max. Load)
where length = 0.5 mile, K = 0.0005, and Max. Load = 171 kWp
The value for K is taken from Ref. 11.

Thus, $\%VD_{AB} = (0.5/2)(0.0005)(171) = 0.02\%$

For $\%VD_{BC}$, the length is 0.9 mile summed at 0.45 mile, the factor K is

0.0003, and the Max. Load is (16 laterals)(171 kWp/lateral) = 2,736 kWp.

Thus, $\%VD_{BC} = (0.9/2)(0.0003)(2{,}736) = 0.37\%$

For $\%VD_{CD}$, the length is 0.2 mile, the factor K is 0.0003, and the Max. Load is approximately 4,000 kWp.

Thus, $\%VD_{CD} = (0.2)(0.0003)(4{,}000) = 0.24\%$

Therefore, the total voltage drop for the system is,

$$\Sigma\%VD = 0.02 + 0.37 + 0.24 = 0.63\%$$

This value is well below the acceptable voltage drop of 5% for the system.

It also suggests the system may be overdesigned, but the money saved using a smaller size cable is not significant for the relatively small amounts used in this design. Too, power losses (I^2R) will kept smaller thus saving money over the long run. Power losses for the system are calculated next.

5.5.3.4 Power Losses

The losses in the system occur primarily in the transformers and the distribution lines. First, the individual losses of the transformers and power lines are found and multiplied by the appropriate number of components or lengths in use. Then, the losses are added to find the total losses in kW per year for the system. Once the total is known, the cost of the losses can be found. The values given below are taken from tables in Ref. 11.

Transformer Losses

The losses for a single-phase 7200-120/240 V distribution transformer rated at 50 kVA and operating at 65°C are given below.

- Core loss = 0.178 kW
- Copper loss = 0.537 kW

These values are at rated voltage, frequency, and kilovoltampere load (Ref. 11).

The losses for a three-phase pad-mounted 12,470/7200 V distribution transformer rated at 250 kVA and 500 kVA are given on the next page.

<u>250 kVA</u>

Core loss = 0.691 kW

Copper Loss = 3.23 kW

<u>500 kVA</u>

Core loss = 1.38 kW

Copper Loss = 6.46 kW

The peak loss for the transformers is,

$$\text{Peak Loss} = \text{Core loss} + \text{Copper Loss}$$

The average loss is,

$$\text{Average Loss} = \text{Core loss} + (\text{Copper loss})(\text{Loss factor})$$

where the Loss Factor is defined as the ratio of the average power loss to the power loss at peak load.

$$F_{LS} = \frac{\text{average power loss}}{\text{power loss at peak load}}$$

The Loss factor can also be approximated by using the following formula,

$$F_{LS} = 0.3F_{LD} + 0.7F_{LD}^2$$

where F_{LD} is the Load factor. From the load survey it was found the residential area has a Load factor of 24.3% and the commercial area has a Load factor of 72%. Thus, the following Loss factors can be found,

Residential Loss factor F_{LS} = 0.114

Commercial Loss factor F_{LS} = 0.579

Thus, the transformer losses are calculated.

50 kVA: Average Loss = 0.178 kW + (0.537 kW)(0.114) = 0.239 kW

250 kVA: Average Loss = 0.691 kW + (3.23 kW)(0.579) = 2.56 kW

500 kVA: Average Loss = 1.38 kW + (6.46 kW)(0.579) = 5.12 kW

Note that the residential Loss factor is used for the 50 kVA transformer because this size transformer is used primarily for the residential area while the larger transformers are for commercial/business use.

<u>Distribution Lines</u>

For the 1/0 cables at 7.2/12.47 kV single-phase and a load factor of 0.25 and an annual peak load per lateral of 607 kW, the I^2R losses are 7,790 kWh/(mi-yr) or 0.889 kW/mi (Ref.xx).

For 1/0 cable three-phase, load factor of 0.6, and an annual peak load per lateral of 586 kW, the I^2R losses are 5550 kWh/(mi-yr) or 0.63 kW/mi.

For the 750 M primary cables at 12.47 kV three-phase and a load factor of 0.35 (average of the residential and commercial load factors) and an annual peak of 10.89 MW, the I^2R losses are estimated at 20 kW/mi.

Table 5-3 below sums up the total losses of the system per year.

TABLE 5-3. SYSTEM LOSSES

<u>Transformers</u>

50 kVA: Peak Loss = 0.715 kW and Average Loss = 0.239 kW

For 235 transformers: Peak Loss = 168 kW & Average Loss = 56 kW

250 kVA: Peak Loss = 3.92 kW and Average Loss = 2.56 kW

For 4 transformers: Peak Loss = 16 kW & Average Loss = 10 kW

500 kVA: Peak Loss = 7.84 kW and Average Loss = 5.12 kW

For 3 transformers: Peak Loss = 24 kW & Average Loss = 15 kW

<u>Distribution Lines</u>

1/0 cable single-phase:	(4.5 miles)(0.889 kW/mi)	=	4.0 kWp
1/0 cable three-phase:	(0.5 mile)(0.63 kW/mi)	=	0.32 kWp
750 cable three-phase:	(0.5 mile)(20 kW/mi)	=	10 kWp
	Total Losses kWp on the system	=	222 kWp

Cost of the Losses

The cost of the losses is based on what APS experiences in their system. The cost is based on the kWp of the losses and is derived from how much more would it cost to provide additional electrical generation to meet the demand of the losses. The dollar amounts are the yearly costs. The cost is broken down in the following manner:

- Cost of Demand: $396/kWp
- Cost of Energy: 2.5 ¢/kWh

For the transformers, the total cost to operate the system for one year is found with the following equation:

Total Cost = Peak Loss x Demand Cost + (Ave. Loss x 8760)(Energy Cost)

For the 50 kVA transformers:

Total Cost = (168)(396) + (56)(8760)(0.025) = $78,800

For the 250 kVA transformers:

Total Cost = (16)(396) + (10)(8760)(0.025) = $8,500

For the 500 kVA transformers:

Total Cost = (24)(396) + (15)(8760)(0.025) = $12,800

Thus, the total cost of losses for the transformers is <u>$100,100.</u>

For the distribution lines, the total cost of losses per year for the distribution lines can be found using the following approximate equation.

$$\text{Total Cost} = \text{Pk. Loss} \times \text{Demand Cost} + (\text{Pk. Loss})(F_{LS})(8760)\ (\text{Energy Cost})$$

For the 1/0 single-phase cable:

$$\text{Total Cost} = (4.0)(396) + (4.0)(0.114)(8760)(0.025) = \$1,700$$

For the 1/0 three-phase cable:

$$\text{Total Cost} = (0.32)(396) + (0.32)(0.579)(8760)(0.025) = \$170$$

For the 750 MCM cable:

$$\text{Total Cost} = (10)(396) + (10)(0.579)(8760)(0.025) = \$5,200$$

Therefore, the total cost of losses for the distribution lines is <u>$7,000,</u> making the total system losses $107,000 per year. This is for the fisrt year only because as the system grows (at 3% a year), the losses in the system will increase as shown in Table 5-4 below.

TABLE 5-4. GROWTH OF SYSTEM LOSSES AND PRESENT WORTH VALUES

Year	Total Cost of Losses	Present value (interest rate = 10%)
0	$ 107,000.00	$ 107,000.00
1	$ 110,210.00	$ 100,190.91
2	$ 113,516.30	$ 93,815.12
3	$ 116,921.79	$ 87,845.07
4	$ 120,429.44	$ 82,254.93
5	$ 124,042.33	$ 77,020.53
6	$ 127,763.60	$ 72,119.22
7	$ 131,596.50	$ 67,529.81
8	$ 135,544.40	$ 63,232.46
9	$ 139,610.73	$ 59,208.58
10	$ 143,799.05	$ 55,440.76
11	$ 148,113.02	$ 51,912.71
12	$ 152,556.41	$ 48,609.18
13	$ 157,133.11	$ 45,515.86
14	$ 161,847.10	$ 42,619.40
15	$ 166,702.51	$ 39,907.26
16	$ 171,703.59	$ 37,367.70
17	$ 176,854.70	$ 34,989.76
18	$ 182,160.34	$ 32,763.14
19	$ 187,625.15	$ 30,678.21
20	$ 193,253.90	$ 28,725.96

Total Present Value: $ 1,258,746.57

Therefore, to build the distribution system requires an approximate cost of $9,545,000 for the initial investment plus an additional $107,000/yr+ to pay for losses on the line. The total present worth value for the design with utility supplied electricity is,

Total Present Worth Value = $9,545,000 + $1,258,746 = <u>$10,803,746</u>

The power company will have to account for the losses, but it might result in a higher cost of electricity depending on the current generation capabilities of the utility. Of course, additional expenses such as maintenance, repair, and replacement cost will occur but they will be the responsibility of the power company.

The maintenance on the distribution system, once in place, would be minimal mainly because the system is underground. The area is subjected to few storms and other hazards which cause outages. In any case, the maintenance required would definitely be less than what the solar PV systems would need, especially for a large central system.

The initial cost of the electrical distribution system must be paid by the developers of the solar village who, in turn, will pass the cost on to the buyers of homes and businesses. However, it's important to realize other factors which may reduce this initial cost.

For example, depending on certain factors such as location of the village and future electrical needs in the area, APS or SRP may be willing to absorb some of the cost of building the distribution system if they feel they can benefit in the long run by selling more electricity. According to engineers at APS, the utility has a surplus of base load electricity from their Palo Verde nuclear plant.

They may be willing to pay for some or all of the cost of providing the means to supply new customers with electricity if the felt they could benefit from increased sales over the years. Right now they are looking at a payback time of two years for their initial investment. It would be unlikely they would foot the bill for the entire cost of the system for the solar village, but some negotiations may be workable.

Another possibility is that the utility may be planning to expand service in a certain part of the state and may include the solar village in their plans depending on the location. Perhaps the distribution substation could be located close enough to another customer who could share the cost of its construction. Other possibilities exist and would have to be looked at closely before the final selection of the site, under this option, is made.

5.5.3.5 Analysis of residential utility-interactive solar PV system

In this section, a cost analysis for a house with the 3 kW solar PV system will be done to see if the PV system can at least pay for itself

within its operating lifetime. In other words, is it still beneficial to have a PV system providing some of the electrical energy to the house in order to reduce electrical bills? The equipment list and corresponding costs for this approach is given in Table A.4 in appendix A. The costs are then entered into the economic spreadsheet program to determine its net present worth. The results follow.

The present value of the costs is = \$38,820

The present value of the benefits is = \$25,724

Therefore, the net present value is = \$25,724 - \$38,820 = -<u>\$13,096</u>

Thus, under these conditions, it would not be profitable to to install a utility-interactive system solar PV system on the houses. However, if certain conditions, such as the cost of electricity or interest rates change, the result may improve. If the cost of electricity were to increase dramatically and the cost of the solar PV modules were to decrease, then a utility-interactive system would become profitable.

5.5.4 Analysis of a Central Solar PV Generating Plant

Over the past decade, many large scale solar PV systems, ranging from 50 kW to 7 MW, have been designed, built, and operated in different

locations throughout the world. Some of these systems have experienced many problems due to poor design, faulty equipment, etc. while others have performed well. Several of these solar projects have been built solely for experimental purposes to determine the feasibility of large scale solar PV power. Most of the systems, however, were designed to provide power to a customer, particularly in remote locations, while their operational performance was studied. The question here is "can the electrical energy needs of the solar village be more efficiently met by building a large central solar PV generating plant close to the village?" This section will attempt to answer this question and again look at factors such as cost, practibility, maintenance, etc.

A detailed design of such a large system is not presented here for several reasons. First, such systems of this size are very complex and are designed to meet the specific requirements of a particular load. In other words, the designs cannot be interchanged because too many variables within the requirements are involved. The equipment needs for each design are different (inverter size, module type, tracking system, etc.), and some equipment like the inverters must be special ordered to fit a particular need. Second, the design of such a system is very involved and is beyond the scope of this report. Lastly, the main purpose is to find approximate cost, practibility, and maintainability of a system large enough to support the needs of the village. This can be done reasonably well without creating a specific design.

From the results of the load survey, the village has a peak summertime demand of approximately 10 MW. While this is a rather large amount of power for a solar PV plant to provide, a 7 MW solar PV plant currently in operation in California shows it can be done. However, some questions must be answered first.

Will the array be mounted on a tracking system or will it be a flat plate array? A tracking array can provide up to 30% more power than a flat plate array given the same amount of modules. But the maintenance costs on a tracking system is much higher because of the increased number of moving parts of the array. Also, a computer system is needed for operation to keep the array aligned to the sun.

Where would the solar plant be located? For purposes of efficiency, the plant needs to be as close as possible to the village without detracting from the beauty of the surroundings or unduly disturbing the natural habitat and wildlife.

At what voltage would the plant operate? This would have to be decided by the designing engineer but generally the voltages at the array are kept low (around 300 to 600 V) for safety and efficiency reasons. A small distribution station would be needed to convert this low voltage to a primary feeder voltage of 12.47 kV to keep losses low.

Would a fulltime operations/maintenance crew be required to keep the solar plant operating? Probably, although the number of people required would have to be determined. A full-time two person crew would be reasonable for operation and maintenance. In any case, paying

these people add to the cost of the plant.

5.5.4.1 Cost Analysis

Approximately how much would such a solar PV generating plant cost to build? Current estimates for large systems put the equipment cost at \$2-\$3 per watt and the installation cost at \$3 per watt. Thus, at 10 MW, the array cost is,

$$\text{Array Cost} = [\$2.5/\text{watt} + \$3.00/\text{watt}](10 \times 10^6 \text{ watt}) = \$55{,}000{,}000$$

Add to this the yearly cost of the *full-time crew*, approximately \$40,000, and maintenance \$10,000 for a period of 20 years brings the total up to approximately,

$$(\$40{,}000 + \$10{,}000)(20 \text{ years}) = \$1{,}000{,}000$$

$$\text{Total} = \$55{,}000{,}000 + \$1{,}000{,}000 = \$56{,}000{,}000$$

Now the cost of the distribution system must be included. From the earlier analysis of the distribution system, this cost is estimated to be \$7,545,000. This value doesn't include the cost of the 69 kV subtransmission line since none is needed. It also reflects a lower cost for the substation because of the lower voltages. However, the losses in the distribution line will be approximately the same at \$107,000/year. Again, the present worth of the losses over 20 years is \$1,258,746.

Now, adding all of these costs together gives a total estimated cost for the central solar PV generating plant.

Total Present Worth Cost = $64,803,000

Other costs such as insurance, taxes, repairs, etc. will add to this total.

SECTION 6

COMPARISON OF ALTERNATE SOLAR VILLAGE PV ENERGY DESIGNS

The major objective of this study is to analyze three different designs for a solar photovoltaic energy system for the solar village and compare their economic feasibility to that of supplying the village with utility generated electricity. This was done through the use of present worth analysis so that the system costs could be compared on an equal basis. The results from this analyses are listed in Table 6-1.

TABLE 6-1. COMPARISON OF SOLAR VILLAGE ENERGY SYSTEM COSTS

Method	Present Worth Value
Stand-alone:	$227,505,000
Stand-alone with interconnection:	$181,521,000
Central plant:	$64,803,000
Utility electricity:	$10,803,746

6.2 DISCUSSION OF ECONOMIC RESULTS

Obviously, the results immediately point out that utility generated electricity is by far cheaper to supply to the village than electricity generated from the sun, even though a new 10 mile 69 kV subtransmission line was assumed to be built.

The cost of supplying electricity through the stand-alone and stand-alone with interconnection designs is extremely expensive. The high cost is due to the very large solar arrays needed to supply the peak demand of the houses and particularly the commercial businesses. The cost of the central plant is closer but still almost six times as much as the utility generated electricity. A short discussion on the cost and practicability of each of the designs follows.

The stand-alone design is the most expensive because it requires the largest solar arrays needed to meet the peak demands of the individual customers. This particulary true for the commercial/business customers because a very large array is necessary just to supply power to a large department or grocery store. Battery backup power is not feasible for these large power customers because the battery arrays would be large, expensive, and difficult to maintain. Diesel generators used for backup power are more practical than battery arrays, but they are still more expensive to buy and maintain than having the utility supply the electricity. They are also polluting, noisy, and subject to mechanical breakdown.

The stand-alone design with interconnection helps to reduce the size of the arrays due to the sharing of power between arrays i.e. through the coincidence factor. However, the arrays still needed are very large and costly. Also, the added cost of the interconnecting distribution system between the residents of the village must be included in this design.

As with the stand-alone design the battery arrays are also very expensive and create additional hazards a homeowner may not want to contend with. Batteries are best for short term temporary power or for light energy needs. Again, a viable alternative mentioned earlier is having backup power being supplied by diesel generators.

However, while they can provide large amounts of power on short notice, the cost of this power is more expensive than what a utility company charges. Diesel generators become economically competitive only when they are used at a site far removed from available utility power. They also suffer from the same problems mentioned earlier.

Perhaps the best solar PV energy method for the solar village, from a practical point of view, is the central solar plant. A large (8-10 MW) array field is built next to the solar village to satisfy all of the electrical needs through a central substation and distribution system. Large diesel generators can provide backup power when needed.

Unfortunately, an array field of this size is very expensive to build, operate, and maintain. A full-time operating and maintenance crew is require to keep the plant operating, with their salaries adding to the cost of this option. Instead of owning their own systems, homeowners would

contribute to the cost of building the solar plant. From the cost anaysis, the central solar plant, while cheaper than the other two solar PV designs, is still more expensive to build and operate than utility supplied electricity.

In the cost analysis, it was assumed that a 10 mile subtransmission line had to be built to provide the solar village with utility company electricity. Even if this distance was doubled, at $150,000/mile, the cost for the line would only be $3 million dollars. Thus, even if the village were far away from existing lines, the utility can still provide electricity at a cheaper cost than any of the solar PV electrical energy designs. This electricity would also be more reliable and the equipment would be maintained by the utility.

SECTION 7

CONCLUSIONS AND RECOMMENDATIONS

Several different solar photovoltaic energy systems, designed to meet the electrical needs of a small community, are not economically feasible to build at this time. Power supplied by the utility companies is less costly, even though a new subtransmission line and substation would have to be built. The main reason for the failure of these designs to supply competitive electricity is the high cost of the solar PV modules, especially when compared to the amount of power they generate.

It's recommended the solar village not be built until solar electricity becomes more competitve with electricity generated by coal, oil, and nuclear energy. However, solar PV energy will continue to be cost effective in those remote areas where there are no transmission lines nearby.

Further studies should continue on ways to provide cheaper solar power and on ways to complement solar PV power, such as solar thermal ponds which can be used for heating and cooling systems and the use of passive solar heating in architecture. Studies on load controlling can also help to reduce the peak demand and thus reduce the system size. Thus, this report serves as a basis from which other studies can start from. The solar village of tomorrow will incorporate many energy saving design features and will one day become a reality in the Arizona desert..

8.0 REFERENCES

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APPENDIX A

LOAD GROWTH AND PRESENT WORTH ANALYSIS

DATA AND RESULTS

TABLE A-1 LOAD GROWTH

	Total Gross 3% Growth			Total Gross		
	January			April		
year	MWH/Mo	MWH/Day	MW/Day	MWH/Mo	MWH/Day	MW/Day
0	1777.0000	56.8600	6.9740	1715.0000	57.1500	5.5270
1	1830.3100	58.5658	7.1832	1766.4500	58.8645	5.6928
2	1885.2193	60.3228	7.3987	1819.4435	60.6304	5.8636
3	1941.7759	62.1325	7.6207	1874.0268	62.4493	6.0395
4	2000.0292	63.9964	7.8493	1930.2476	64.3228	6.2207
5	2060.0300	65.9163	8.0848	1988.1550	66.2525	6.4073
6	2121.8309	67.8938	8.3273	2047.7997	68.2401	6.5995
7	2185.4859	69.9306	8.5771	2109.2337	70.2873	6.7975
8	2251.0504	72.0285	8.8345	2172.5107	72.3959	7.0014
9	2318.5819	74.1894	9.0995	2237.6860	74.5678	7.2115
10	2388.1394	76.4151	9.3725	2304.8166	76.8048	7.4278

	Total Gross 3% Growth			Total Gross		
	August			October		
year	MWH/Mo	MWH/Day	MW/Day	MWH/Mo	MWH/Day	MW/Day
0	2732.0000	88.1600	10.8930	1952.0000	63.0000	5.8440
1	2813.9600	90.8048	11.2198	2010.5600	64.8900	6.0193
2	2898.3788	93.5289	11.5564	2070.8768	66.8367	6.1999
3	2985.3302	96.3348	11.9031	2133.0031	68.8418	6.3859
4	3074.8901	99.2249	12.2602	2196.9932	70.9071	6.5775
5	3167.1368	102.2016	12.6280	2262.9030	73.0343	6.7748
6	3262.1509	105.2677	13.0068	2330.7901	75.2253	6.9780
7	3360.0154	108.4257	13.3970	2400.7138	77.4821	7.1874
8	3460.8159	111.6785	13.7989	2472.7352	79.8065	7.4030
9	3564.6403	115.0288	14.2129	2546.9173	82.2007	7.6251
10	3671.5795	118.4797	14.6393	2623.3248	84.6667	7.8538

TABLE A-2 SOLAR INSOLATION LEVELS

Insolation on Collector, kWh/m2-d	January	February	March	April	May	June	July
Collector Tilt							
Horizonal	3.22	4.34	5.72	7.43	8.44	8.64	7.84
20 degrees	4.32	5.33	6.38	7.65	8.19	8.18	7.51
25 degrees	4.53	5.51	6.46	7.6	8.02	7.95	7.33
30 degrees	4.72	5.66	6.51	7.52	7.81	7.69	7.11
35 degrees	4.88	5.77	6.52	7.39	7.56	7.38	6.86
40 degrees	5.01	5.85	6.49	7.22	7.26	7.04	6.57
45 degrees	5.11	5.89	6.42	7.[illegible]1	6.93	6.66	6.25
50 degrees	5.18	5.89	6.31	6.76	6.56	6.25	5.89
Vertical	4.52	4.68	4.26	3.63	2.66	2.1	2.21

Insolation on Collector, kWh/m2-d	August	September	October	November	December	YEAR
Collector Tilt						
Horizonal	7.23	6.36	4.97	3.63	2.94	5.9
20 degrees	7.25	6.85	5.9	4.74	4.07	6.37
25 degrees	7.16	6.89	6.05	4.95	4.3	6.4
30 degrees	7.04	6.88	6.17	5.14	4.5	6.4
35 degrees	6.87	6.84	6.26	5.3	4.68	6.36
40 degrees	6.67	6.76	6.3	5.42	4.82	6.28
45 degrees	6.43	6.64	6.31	5.5	4.94	6.17
50 degrees	6.16	6.48	6.28	5.55	5.02	6.03
Vertical	3.01	4.03	4.72	4.72	4.51	3.75

TABLE A-3 EQUIPMENT LIST AND COSTS FOR STAND-ALONE DESIGN

Major Components

EQUIPMENT ITEM	TYPE AND/OR SIZE	QUANTITY	PRICE PER UNIT	TOTAL COST
1. Power Conditioning Unit	Photoelectric SI-3000	1	$2,210	$2,210
2. Square D main panelboard	Model NQO, 100A mains	1	$ 513.00	$513
3. Square D circuit breakers	120/240 VAC	15	Varies (approx. $35)	$525
5. Solar modules	ARCO Solar M55	72	$ 343.00	$24,696
6. SCG combiner J-box	Square D	1	$413	$413
7 Shawmut fuses	Various sizes	20	Varies (approx. $10)	$200
8. Voltmeter	Trace 12DVM	1	$ 104.00	$104
9. Varistors a.) In Array	Panasonic-ERZC20DK220	12	$27	$324
b.) In Interface	Panasonic-ERZC10DK361	2	$35	$70
10. Battery cables	Trace BC5	25	$ 25.00	$625
11. DC 100 Amp Breaker	Square D Cat.#Q02000NAS	1	$94	$94
12. AC Disconnent Switch	Leviton Cat.# 1122	1	$74	$74
			TOTAL:	$ 29,848.00

TABLE A-4 EQUIPMENT LIST AND COSTS FOR INTERCONNECTION DESIGNS

Major Components EQUIPMENT ITEM	TYPE AND/OR SIZE	QUANTITY	PRICE PER UNIT	TOTAL COST
Square D main panelboard	Model NQO, 100A mains	1	$ 513.00	$513
Square D circuit breakers	120/240 VAC	15	Varies (approx. $35)	$525
Storage batteries	I.B.E. 6-75N33	44	$ 340.00	$14,960
Solar modules	ARCO Solar M55	149	$ 343.00	$ 51,107.00
Battery charger/controller	BOSS, Inc. 48VDC-20A	1	$ 213.00	$231
SCG combiner J-box	Square D	1	$413	$413
Shawmut fuses	Various sizes	20	Varies (approx. $10)	$200
Voltmeter	Trace 12DVM	1	$ 104.00	$104
Varistors a.) In Array	Panasonic-ERZC20DK220	12	$27	$324
b.) In Interface	Panasonic-ERZC10DK361	2	$35	$70
Battery cables	Trace BC5	25	$ 25.00	$625
Power Inverter	Dynamote UXB 6.0-48	1	$1,266	$1,266
DC 100 Amp Breaker	Square D Cat.# Q02000NAS	1	$94	$94
AC Disconnent Switch	Leviton Cat.# 1122	1	$74	$74
			TOTAL:	$70,488

TABLE A-5 PRESENT WORTH ANALYSIS: STAND-ALONE DESIGN

	A	B
1	PV SYSTEM CRITERIA	Stand-alone
2	1. PV-array size A,m2	107
3		
4	2. PV-array packing factor PF	0.9
5		
6	3. PV module efficiency PVE at NOCT,%	13
7		
8	4. Power inverter efficiency PCE,%	90
9		
10	5. PV-array peak power PP at NOCT, Wp	
11	PP = 1000 X A X PF X PVE/100	12519
12		
13	6. PV-system expected useful lifetime L, yr	25
14		
15	PHOTOVOLTAIC SYSTEM COSTS	
16		
17	1. Peak-watt PV module costs MC, $/Wp	$ 6.47
18		
19	2. PV-array costs PVC, $	
20	PVC = MC X PP =	$ 80,997.93
21		
22	3. PV-array support structure costs SC, $	zero, integral mount
23		
24	4. PV-system power conditioning costs PC, $	$ 1479.00
25		
26	4.a. Battery costs BC, $	$ 14,960.00
27		
28	5. PV wiring materials costs WC, $	$ 2960.00
29		
30	6. Design and installation labor costs LC, $	$ 3000.00
31		
32	7. Annual property tax increase PT resulting	
33	from addition of PV system, $	$ 50.00
34		
35	8. Annual insurance premium for PV system IC, $	$ 125.00
36		
37	9. Annual PV-system maintenance costs MC, $	$ 100.00

10. Predicted average annual price escalation rate	8
over lifetime of PV system ER1, %	
11. Predicted average annual discount rate for	
borrowing money over lifetime of PV-system DR1, %	10
12. Uniform present worth of costs UPW1 based on L,	19.87
ER1, and DR1	
13. Percentage of PV-system costs deducted for tax or	
depreciation credit TC, %	0
14. Salvage value SV after system lifetime, $	$ 1000.00
15. Total PV-system costs TPC, $	$ 107,861.18
TPC = {[(PP X PVC) + SC + PC + WC + LC +	
UPW1 X (20)] - SV} X (100 - TC)/100	
16. Loan down payment DP, $	$ 10,000.00
17. Term of loan TL, yr	10
18. Loan discount rate DR2, %	10
19. Predicted average annual price escalation rate	8
over term of loan ER2, %	
20. Loan uniform present worth UPW2 based on TL,	9.05
ER2, and DR2	
21. Loan monthly payments MP throughout duration	
of term, $	
MP = [(TPC-DP)*0.1993]/12	$ 1,625.31
22. Present value of PV system costs NSC, $	
NSC = DP + (TPC-DP) X (TL/UPW2) =	$ 118,133.90
PHOTOVOLTAIC SYSTEM BENEFITS	

79	1. Annual average daily solar energy SE, kWh/m2•d	6.37
80		
81	2. Utilization factor	1.00
82		
83	3. Present available electricity costs EC, $/kWh	0.0723
84		
85	4. Predicted average annual escalation rate of	15
86	electricity prices over lifetime of PV system ER3, %	
87		
88	5. Discount rate for alternative investment	12
89	opportunities DR3, %	
90		
91	6. Benefit uniform present worth UPW3 based on L,	35.9
92	ER3, and DR3	
93		
94	7. Annual PV -system useful output PVO, kWh/yr	26,196.57
95	PVO = 365 X SE X A X PF X PVE/100 X PCE/100 X U =	
96		
97	8. Present value of PV-system output over lifetime VPO	
98	VPO = PVO X EC X UPW3 =	$ 67,995.03
99		
100	NET PRESENT VALUE	
101		
102	1. System benefits minus costs NPV, $	
103	NPV = VPO - NSC =	($ 50,138.37)

TABLE A-6 PRESENT WORTH ANALYSIS: INTERCONNECTION DESIGN

	C	D
1	PV SYSTEM CRITERIA	Stand-alone w/ inter
2	1. PV-array size A,m2	63
3		
4	2. PV-array packing factor PF	0.9
5		
6	3. PV module efficiency PVE at NOCT,%	13
7		
8	4. Power conditioning efficiency PCE,%	90
9		
10	5. PV-array peak power PP at NOCT, Wp	
11	PP = 1000 X A X PF X PVE/100	7371
12		
13	6. PV-system expected useful lifetime L, yr	25
14		
15	PHOTOVOLTAIC SYSTEM COSTS	
16		
17	1. Peak-watt PV module costs MC, $/Wp	$ 6.47
18		
19	2. PV-array costs PVC, $	
20	PVC = MC X PP =	$ 47,690.37
21		
22	3. PV-array support structure costs SC, $	zero, integral mount
23		
24	4. PV-system power conditioning costs PC, $	$ 3400.00
25		
26	4.a. Battery costs BC,$	$ 14960.00
27		
28	5. PV wiring materials costs WC, $	$ 2960.00
29		
30	6. Design and installation labor costs LC, $	$ 3000.00
31		
32	7. Annual property tax increase PT resulting	
33	from addition of PV system, $	$ 0.00
34		
35	8. Annual insurance premium for PV system IC, $	$150
36		
37	9. Annual PV-system maintenance costs MN, $	$125

10. Predicted average annual price escalation rate	8
over lifetime of PV system ER1, %	
11. Predicted average annual discount rate for	
borrowing money over lifetime of PV-system DR1, %	10
12. Uniform present worth of costs UPW1 based on L,	19.87
ER1, and DR1	
13. Percentage of PV-system costs deducted for tax or	
depreciation credit TC, %	0
14. Salvage value SV after system lifetime, $	$ 1000.00
15. Total PV-system costs TPC, $	$ 61,514.62
TPC = {[(PP X MC) + SC + PC + WC + LC +	
UPW1 X (275)] - SV} X (100 - TC)/100	
16. Loan down payment DP, $	$ 10,000.00
17. Term of loan TL, yr	10
18. Loan discount rate DR2, %	10
19. Predicted average annual price escalation rate	8
over term of loan ER2, %	
20. Loan uniform present worth UPW2 based on TL,	9.05
ER2, and DR2	
21. Loan monthly payments MP throughout duration	
of term, $	
MP = [(TPC-DP)*0.1993]/12	$ 855.57
22. Present value of PV system costs NSC, $	
NSC = DP + (TPC-DP) X (TL/UPW2) =	$ 66,922.23
<u>PHOTOVOLTAIC SYSTEM BENEFITS</u>	

79	1. Annual average daily solar energy SE, kWh/m2•d	6.37
80		
81	2. Utilization factor	1.00
82		
83	3. Present available electricity costs EC, $/kWh	0.0723
84		
85	4. Predicted average annual escalation rate of	15
86	electricity prices over lifetime of PV system ER3, %	
87		
88	5. Discount rate for alternative investment	12
89	opportunities DR3, %	
90		
91	6. Benefit uniform present worth UPW3 based on L,	35.9
92	ER3, and DR3	
93		
94	7. Annual PV -system useful output PVO, kWh/yr	15,424.15
95	PVO = 365 X SE X A X PF X PVE/100 X PCE/100 X U =	
96		
97	8. Present value of PV-system output over lifetime VPO	
98	VPO = PVO X EC X UPW3 =	$ 40,034.46
99		
100	<u>NET PRESENT VALUE</u>	
101		
102	1. System benefits minus costs NPV, $	
103	NPV = VPO - NSC =	($ 26,887.77)

TABLE A-7 PRESENT WORTH ANALYSIS: UTILITY INTER-TIE

	E	F
1	PV SYSTEM CRITERIA	Utility-intertie
2	1. PV-array size A,m2	31
3		
4	2. PV-array packing factor PF	0.9
5		
6	3. PV module efficiency PVE at NOCT,%	13
7		
8	4. Power conditioning efficiency PCE,%	90
9		
10	5. PV-array peak power PP at NOCT, Wp	
11	PP = 1000 X A X PF X PVE/100	3627
12		
13	6. PV-system expected useful lifetime L, yr	25
14		
15	PHOTOVOLTAIC SYSTEM COSTS	
16		
17	1. Peak-watt PV module costs MC, $/Wp	$ 6.47
18		
19	2. PV-array costs PVC, $	
20	PVC = MC X PP =	$ 23,466.69
21		
22	3. PV-array support structure costs SC, $	zero, integral mount
23		
24	4. PV-system power conditioning costs PC, $	$ 2210.00
25		
26		
27		
28	5. PV wiring materials costs WC, $	$ 2942.00
29		
30	6. Design and installation labor costs LC, $	$ 3000.00
31		
32	7. Annual property tax increase PT resulting	
33	from addition of PV system, $	$ 0.00
34		
35	8. Annual insurance premium for PV system IC, $	$150
36		
37	9. Annual PV-system maintenance costs MN, $	$125

38		
39	10. Predicted average annual price escalation rate	8
40	over lifetime of PV system ER1, %	
41		
42	11. Predicted average annual discount rate for	
43	borrowing money over lifetime of PV-system DR1, %	10
44		
45	12. Uniform present worth of costs UPW1 based on L,	19.87
46	ER1, and DR1	
47		
48	13. Percentage of PV-system costs deducted for tax or	
49	depreciation credit TC, %	0
50		
51	14. Salvage value SV after system lifetime, $	$ 1000.00
52		
53	15. Total PV-system costs TPC, $	$ 36,082.94
54	TPC = {[(PP X MC) + SC + PC + WC + LC +	
55	UPW1 X (275)] - SV} X (100 - TC)/100	
56		
57	16. Loan down payment DP, $	$ 10,000.00
58		
59	17. Term of loan TL, yr	10
60		
61	18. Loan discount rate DR2, %	10
62		
63	19. Predicted average annual price escalation rate	8
64	over term of loan ER2, %	
65		
66	20. Loan uniform present worth UPW2 based on TL,	9.05
67	ER2, and DR2	
68		
69	21. Loan monthly payments MP throughout duration	
70	of term, $	
71	MP = [(TPC-DP)*0.1993]/12	$ 433.19
72		
73		
74	22. Present value of PV system costs NSC, $	
75	NSC = DP + (TPC-DP) X (TL/UPW2) =	$ 38,820.93
76		
77		
78	PHOTOVOLTAIC SYSTEM BENEFITS	

79	1. Annual average daily solar energy SE, kWh/m2•d	6.37
80		
81	2. Utilization factor	1.00
82		
83	3. Present available electricity costs EC, $/kWh	0.0723
84		
85	4. Predicted average annual escalation rate of	15
86	electricity prices over lifetime of PV system ER3, %	
87		
88	5. Discount rate for alternative investment	10
89	opportunities DR3, %	
90		
91	6. Benefit uniform present worth UPW3 based on L,	46.88
92	ER3, and DR3	
93		
94	7. Annual PV -system useful output PVO, kWh/yr	7,589.66
95	PVO = 365 X SE X A X PF X PVE/100 X PCE/100 X U =	
96		
97	8. Present value of PV-system output over lifetime VPO	
98	VPO = PVO X EC X UPW3 =	$ 25,724.58
99		
100	NET PRESENT VALUE	
101		
102	1. System benefits minus costs NPV, $	
103	NPV = VPO - NSC =	($ 13,096.35)

AMENDMENT 1

HARMONIC ANALYSIS

This amendment is intended to supplement the earlier discussion on the effects PV system generated harmonics have on utility generated electricity. When the solar PV system is excited, the PCU unit will generate harmonics of varying frequencies. These harmonics are injected into the utility's electrical system where they can cause undesireable distortion in the voltage and current waveforms. The lower order harmonics are small in amplitude and have little effect on the utility voltage.

For example, in ref. 5, tests were done on a 4 kW utility interactive inverter to determine if harmonic injection was a problem. Their results showed that a 60 hz filter on the output of the PCU attenuated all of the harmonics to varying degrees, especially the lower order harmonics. For a frequency range from 0 to 1000 Hz, they found very small increases in the low, odd harmonics with PV system excitation and concluded these harmonics have little detrimental effect on the system. Harmonics generated by higher frequencies, however, can cause greater distortion on the system. These high frequency harmonics are generated by the high frequency switching in the PCU inverter, including the SI-3000.

Thus, does there need to be an additional filter between the SI-3000 PCU and the utility service line to filter out these unwanted harmonics? The answer turns out to be no according to the people who designed and tested the SI-3000.

Mr. James Ross, formerly with the Photoelectric, Inc. company, designed the SI-3000 PCU several years ago. According to Mr. Ross, high frequency EMI is filtered out in the PCU by a choke capacitance and a PI network filter. There is less than 5% current harmonic distortion from 1/4 to full power and less than 1% voltage harmonic distortion over the same range.

Mr. Ross said that a 30 kHz square wave is fed into the inverter and that the 44th harmonic is the most significant harmonic generated. The PI filter use to clean up this distortion consists of a 3 mH inductor choke together with a 7.5 µF shunt capacitor in series with a 2.2 Ω damping resistor.Mr. Ross concluded saying no additional filters are needed between the SI-3000 and the utility service line.

When asked whether 900 such systems were connected together, as they would be in the solar village, would have an adverse effect on the utility voltage and current waveforms, he replied no. He said because the individual PCUs would be operating independently, the average total value of the harmonic distortion would actually decrease. He cited an experiment on-going in California were 36 houses, each with its own utility-interactive solar PV system, were operating trouble free and did not suffer from harmonic distortion affects.

Sandia Labs, located in Albuquerque, New Mexico, does extensive testing of solar PV equipment as it comes on the market. A thorough test was conducted recently on the SI-3000 PCU to evaluate performance, efficiency, etc.

According to the engineers who did the testing, no additional filtering is needed between the output of the PCU and the utility service line to filter out harmonics. This is again because of the internal filtering of the PCU and because any harmonics that were generated and injected into the utility line would be insignificant. Also, if four solar PV systems were connected into one 50 kVA distribution transformer, as they would be in the solar village, the ratio of 12 kW to 50 kVA is such that the stiffness of the utility voltage and current waveforms would not suffer appreciably from any distortion injected by the PCU.

Thus, because of this information, the unavailibility of detailed information on the exact harmonic outputs, and of time constraints, no further analysis on the design of an additional output filter for the SI-3000 PCU will be done. The solar village will be able to operate without them.

BIOGRAPHICAL SKETCH

Eric Carl Pierce-French [redacted] received his elementary education at Central Elementary School in La Grande, Oregon. He attended La Grande Senior High School and graduated in 1978. That same year he entered Eastern Oregon State College and was awarded a Bachelor of Science degree in Physics in 1982. He joined the U.S. Air Force in 1982 and completed Officers Training School the same year. He attended Louisiana Tech University and was awarded a Bachelor of Science degree in Electrical Engineering in 1984. From 1984 to 1986 he worked at Francis E. Warren AFB in Cheyenne, Wyoming. In August, 1986 he entered the Graduate College at Arizona State University in the field of Electrical Engineering-Power Systems. He is currently a Captain in the U.S. Air Force and is a member of Sigma Pi Sigma Honorary Society.